ATTACHMENT 2

Congestion Management Process

Congestion Management Process

Version 4.01

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Revision History

DATE	EDITOR	VERSION	SUMMARY OF CHANGES
1/13/03	Tow Bowe	Draft 1	Initial draft
2/15/03	Tom Bowe	Draft 2	Added more detail for several topics
4/16/03	Andy Rodriquez	Final	See detailed change summary
4/28/03	Andy Rodriquez	Final-C01	Changes per PJM/MISO Review Team requests
5/9/03	Andy Rodriquez	Final-C02	Added 0%+counterflow change
5/16/03	Andy Rodriquez	Final-C03	Spelling correction, updated examples
8/4/03	Andy Rodriquez	V4-Final	Marginal Zone calculation methodology; NNL and Market Flow calculation methodology; timeline for data exchange between reciprocal entities
4/2/04	Andy Rodriquez	V4.01-Final	Explanations and Clarifications per FERC Directive (ER04-375-000).

Executive Summary

This is the final version of the PJM/MISO Congestion Management Process document. This version differs significantly from the previous drafts, providing far more detail in the areas of Market Flow Calculation; Firm Gen-to-Load Flow determination; the Tagging of Import and Export transactions; and Flowgate determination. These additional details are the result of multiple meetings between the Operating Entities, as well as meetings with the NERC community and the industry's associated stakeholders. Some of these review meetings included:

- *Joint NERC CMS, IDCWG, and MISO/PJM Review Team (NERC ORS and RCWG) Meetings*
- *NERC Interchange Subcommittee Meeting*
- *MAIN Operating Committee Meetings*
- *ECAR CRC and Executive Board meetings*
- *MISO/PJM Open Stakeholders Meetings*

As PJM and MISO expand and implement their respective markets, one of the primary seams issues that must be resolved is how different congestion management methodologies (market-based and traditional) will interact to ensure that parallel flows and impacts are recognized and controlled in a manner that consistently ensures system reliability. PJM and MISO have actively worked with stakeholders in various forums in order to identify and address various concerns and issues. We have addressed these issues in this process. Responses to issues and questions raised by stakeholders are provided in Appendix H. While developed specifically to address the congestion management seams between the MISO and PJM, the concepts in this process are intended to provide a robust framework that may be used by other Operating Entities as they implement markets over large regions. The proposed solution will greatly enhance current IDC granularity by utilizing existing real-time applications to monitor and react to Flowgates external to an Operating Entity's market footprint. PJM is a Market-Based Operating Entity that plans to expand its area, and MISO is starting its Market Operations and is becoming a Market-Based Operating Entity. In brief, the process includes the following concepts:

- *Participating Operating Entities will agree to observe limits on an extensive list of coordinated external Flowgates*
- *Like all Control Areas, Market-Based Operating Entities will have Firm Gen-to-Load Flows upon those Flowgates.*
- *Market-Based Operating Entities will determine these Firm Gen-to-Load Flows using the published analysis process, and constrain their operations to limit Firm*

Gen-to-Load Flows on the Coordinated Flowgates to no more than the calculated Firm Gen-to-Load Limit established in the analysis.

- *In real-time, Market-Based Operating Entities will calculate and monitor when the projected and actual flows exceed the Firm Gen-to-Load Limits established in the day-ahead process.*
- *Market-Based Operating Entities will post the Firm Gen-to-Load Flow and additional non-firm economic market flow, as well as the actual and projected market flow, to the IDC for both internal and external Coordinated Flowgates.*
- *Market-Based Operating Entities will provide to the IDC detailed representation of their marginal units, so that the IDC can continue to effectively compute the effects of all tagged transactions regardless of the size of the market area. These tagged transactions will include transaction into the market, transactions out of the market, and tagged grandfathered transactions within the market.*
- *When there is a TLR 3a or higher called on a Coordinated Flowgate, and the Market-Based Operating Entity's actual/projected Market Flows exceed the Firm Gen-to-Load Limits, Market-Based Operating Entities will redispatch in order to provide the required MW relief, per the IDC congestion management report.*
- *When there is a TLR 5a or 5b, all TPs will curtail or redispatch their respective systems to provide their shares of NNL reductions as directed by the IDC.*
- *Because the IDC will have the real-time/projected flows throughout the Market-Based Operating Entity's system (as represented by the impacts upon various Coordinated Flowgates), the effectiveness of the IDC will be greatly enhanced.*
- *The above processes refer to the "Congestion Management" portion of the paper, which may be implemented by Market-Based Operating Entities. PJM will implement the Congestion Management portions of this process at the time Commonwealth Edison is integrated into the PJM Market; the Midwest ISO will implement the Congestion Management portions of this process when it implements its market.*
- *Entities may choose to enter into reciprocal coordination agreements with MISO and/or PJM that describe how ATC/AFC, Firm Flows, and outage maintenance will be coordinated on a forward basis. PJM and MISO have agreed to implement a Reciprocal Coordination Agreement beginning when PJM integrates Commonwealth Edison into its market. MISO will begin reciprocation with PJM at that time with regard to Flowgate Allocation and AFC coordination; Midwest ISO will conduct the congestion management portions of this process when it implements its market.*

- *The complete process will allow participating Operating Entities to address the reliability aspects of congestion management seams issues between all parties whether the seams are between market to non-market operations or market to market operations.*

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Change Summary

Note: All items below are intended to clarify this document based on requests from the FERC in ER04-375-000. No material changes have been made to this document.

- Ensured consistent definitions between JOA and this document
- Clarified Flowgates in more detail; described Coordinated Flowgates, Reciprocal Coordinated Flowgates
- Clarified study criteria for determining Coordinated Flowgates
- Restructured document to clarify differences between 'Market Based Operating Entities" and "Reciprocal Entities"
- Restructured document to clarify differences between Congestion Management processes and Reciprocal processes
- Clarified differences between Point-to-Point and Gen-to-Load impacts (previous versions used generic term "NNL" for both)
- Clarified Reciprocal Allocation process, including additional detail where necessary
- Updated Reciprocal Coordinated Flowgate List
- Marginal Zone Weighting for Multi-CA configurations simplified

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Section 1 - Introduction

As **Market-Based Operating Entities** expand and implement their respective markets, one of the primary seams issues that must be resolved is how congestion management will be implemented in coordination with other areas, both those that have similar markets and those that do not. PJM and the Midwest ISO (MISO) have actively worked with stakeholders in various forums in order to identify and address their respective concerns and issues regarding congestion management. We have addressed these issues in this process.

This is the fourth revision of the PJM/MISO Congestion Management Process. This revision differs significantly from the previous drafts, providing far more detail in the areas of Market Flow Calculation; Firm Gen-to-Load Flow determination; the tagging of import and export transactions; and Flowgate determination. These additional details are the result of multiple meetings between the Operating Entities, as well as meetings with the NERC community and the industry's associated stakeholders. Some of these review meetings included:

- Joint NERC CMS, IDCWG, and MISO/PJM Review Team (NERC ORS and RCWG) Meetings
- NERC Interchange Subcommittee Meeting
- MAIN Operating Committee Meetings
- ECAR CRC and Executive Board Meetings
- MISO/PJM Open Stakeholders Meetings

It is the intention of PJM and MISO to utilize the processes proposed within this document until both Operating Entities are operating within a joint and common market. It is further our intention to develop this process in a way that will allow other regional entities with similar concerns to utilize the concepts within this process to aid in the resolution of their own seams issues. PJM and MISO may recommend changes and improvements as operations continue and as each Operating Entity establishes full but independent markets.

Problem Definition

The Nature of Energy Flows

Energy flows are distinctly different from the manner in which the energy commodity is purchased, sold, and ultimately scheduled. In the current practice of "contract path" scheduling, schedules identify a source point for generation of energy, a series of wheeling agreements being utilized to transport that energy, and a specific sink point where that energy is being consumed by a load. However, due to the electrical reality of the Eastern Interconnection, energy flows are much different than what is described within that schedule. This disconnect becomes of concern when there is a need to take actions on contract-path schedules to effect changes on the physical system (for example, the curtailment of schedules to relieve transmission constraints).

In the Eastern Interconnection, much of this concern has been addressed through the use of the NERC Transmission Loading Relief (TLR) process. Through this process, Reliability Coordinators utilize the *Interchange Distribution Calculator (IDC)* to determine appropriate actions to provide that relief. The IDC bases its calculations on the use of transaction tags: electronic documents that specify a source and a sink, which can be used to estimate real power flows through the use of a network model. In order to change flows, the IDC is given a particular constraint and a desired change in flows. The IDC returns back all source to sink transactions that contribute to that constraint and specify schedule changes to be made that will effect that change in flows.

In other parts of the Eastern Interconnection, however, the use of centralized economic dispatch results in a solution that does not focus on changing entire transactions (effectively redispatching through the use of imbalance energy), but rather redispatch itself. In this procedure, the party attempting to provide relief does not need to know that a balanced source to sink transaction should be adjusted; rather, they are aware of a net generation to load balance and the impacts of different generators on various constraints. Locational Marginal Pricing is a regional implementation of this practice.

Currently, these two practices are somewhat incompatible. Due to the electrical characteristics of the Interconnection and geographic scope of the regions, this incompatibility has been of limited concern. However, regional market expansion has begun to draw attention to this philosophical disjoint, as the expansion itself exacerbates the negative effects of the incompatibility.

Granularity in the IDC

The IDC uses an approximation of the Interconnection to identify impacts on a particular transmission constraint that are caused by flows between Control Areas. This approximation allows for a Reliability Coordinator to identify tagged transactions with specific sources and sinks that are contributing to the constraint. While tagged transactions may specify sources and sinks in a very specific manner, the IDC in general cannot respect this detail, and instead consolidates the impacts of several generators and loads into a homogenous representation of the impacts of a single Control Area. This is referred to as the *granularity* of the IDC. Current granularity is typically defined to the Control Area level; finer granularity is present in certain special situations as deemed necessary by NERC.

Reduced Data and Granularity Coarseness

As centrally dispatched energy markets expand their footprint, two related changes occur with regard to the above process. In some cases, data previously sent to the IDC is no longer sent due to the fact that it is no longer tagged. In others, transactions remain tagged, but the increased market footprint results in an increase in granularity coarseness within the IDC.

In the first change, the transactions contained entirely within the market footprint are considered to be utilizing network service (even when the market spans multiple Control Areas, as is the case with the MISO). As such, there is no requirement for them to be tagged, and therefore, no requirement that they be sent to the IDC. This is of concern from a reliability perspective, as the IDC no longer has a large a pool of transactions from which to provide relief, although the energy flows may remain consistent with those prior to the market expansion. In other words, flows subject to TLR curtailment prior to the market expansion are no longer available for that process.

In the second change, the expansion of the footprint itself results in a corruption of the approximation utilized by the IDC. When a market region is relatively small (or isolated), the approximation of that region's impact on transmission constraints is acceptable; actions within the market footprint generally have a similar and consistent impact on all transmission facilities outside the footprint. However, when the market footprint expands significantly, the ability to utilize an electrically representative approximation becomes difficult. Impacts on external facilities can vary significantly depending on the dispatch of the resources within the market footprint. With regard to the IDC, this information is effectively lost within the expanded footprint, and results in an increase in the level of granularity coarseness, or a "loss of granularity."

Conclusion

The net effect of these changes is that reliability must be managed through different processes than those used before the market region's expansion. While relief can still be requested using the current process, both the ability to predict the ability of a transaction to provide that relief and the general pool of transactions available for curtailment are reduced. <u>This process offers a strategy for eliminating this concern through a process that provides more information (finer granularity) to the NERC IDC. This new congestion management process will ensure that reliability is only increased as markets expand by providing information and relief opportunities previously unavailable to the IDC</u>.

Process Scope and Limitations

Vision Statement

As Operating Entities expand and implement their various markets, one of the primary seams issues that must be resolved is how different congestion management methodologies (market-based and traditional TLR) will interact to ensure parallel flows and impacts are recognized and controlled in a manner that consistently ensures system reliability. For these entities, this process will offer a manner in which Market-Based Operating Entities can coordinate parallel flows with Operating Entities that have not yet implemented markets. Unlike the existing process, this process will provide more proactive management of transmission resources, more accurate information to Reliability Coordinators, and more candidates for providing relief when reliability is threatened due to transmission overload conditions.

Process Scope

While this process has been written specifically with the goal of coordinating seams between PJM and the Midwest ISO and their respective neighbors, this document may be beneficial to any Operating Entity facing similar seams issues related to congestion management. We offer this process as a way to achieve coordination between entities, and propose it as a potential option for any entities that wish to coordinate with each other.

Goals and Metrics

In preparing this document, we focused our solution on meeting the following goals and requirements:

a. Develop a congestion relief process whereby transmission overloads can be eliminated through a shared/effective reduction in Flowgate or constraint usage by MISO, PJM, and other Reliability Coordinators.

b. Agree on a predefined set of Flowgates or constraints to be considered by both organizations, and a process to maintain this set as necessary.

c. Determine the best way to calculate net flow due to one market's impact on a defined set of Flowgates.

d. Develop reciprocal agreements that establish how each Operating Entity will consider its own Flowgate or constraint usage as well as the usage of other Operating Entities when it determines the amount of Flowgate or constraint capacity remaining.

e. Develop a procedure for managing congestion when Flowgates are impacted by both tagged and non-tagged energy flow.

f. Develop a procedure for determining the priorities of untagged energy flows (created through parallel flows from the market).

g. Agree on steps to be taken by Operating Entities to unload a constraint on a shared basis.

h. Determine whether procedure(s) for managing congestion will differ based on where the Flowgate is located (i.e., inside PJM, inside MISO, outside both PJM and MISO).

i. Confirm that the solution will be equitable for all parties, auditable, and independent.

Assumptions

The following assumptions were made as we considered the possible solutions for addressing these issues:

a. Point-to-Point schedules sinking in, sourcing from, or passing through a Market-Based Operating Entity will still be tagged.

b. The IDC is needed for at least the interim between the Interconnection's current state and full implementation of SMD.

c. The Market-Based Operating Entity can compute the impacts of the market dispatch on the Flowgates as required by the IDC

d. The Market-Based Operating Entity's EMS has the capability to monitor and respond to real-time and projected flows created by its real-time dispatch

e. The Reliability Coordinator of the area in which a Flowgate exists will be responsible for monitoring the Flowgate, determining any amount of relief needed, and entering the required relief in the IDC.

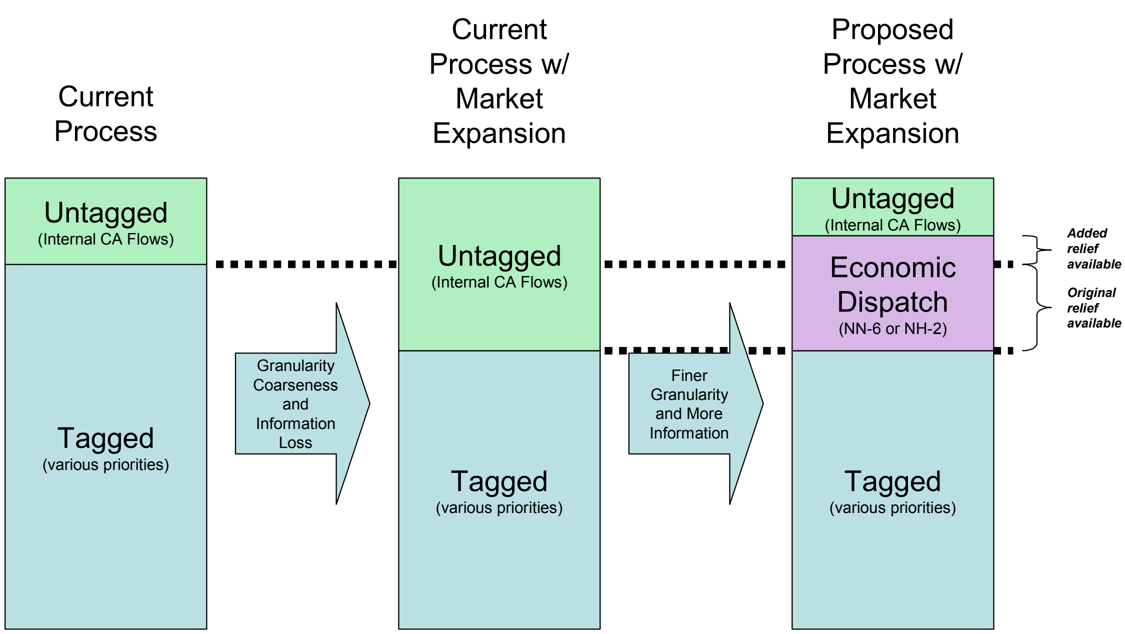
f. The IDC can be modified to accept the calculated values of the impact of real-time generation in order to determine which schedules require curtailment in conjunction with the required Market-Based Operating Entity's redispatch

g. The IDC will calculate the total amount of MW relief required by the Market-Based Operating Entity (schedule curtailments required plus the relief provided by redispatch).

Section 2 - Process Overview

Summary of Process

In order to coordinate congestion management, a bridge must be established that provides for comparable actions between Operating Entities. Without such a bridge, it is difficult, if not impossible, to ensure reliability and system coordination in an efficient manner. To effect this coordination of congestion management activities, we propose a methodology for determining both firm and non-Firm Flows resulting from Market-Based Operating Entity dispatch on external parties' Flowgates.



Market Flows are defined as the flows generated from an operational entity's dispatch, and is equal to the sum of firm and non-Firm Flows. The firm components consist of the flows created both through serving native load and by those schedules flowing on Firm Point-to-Point transmission reservations (7-F). For the purposes of this process, both firm point-to-point transmission and native load schedules will be referred to as the **Firm Flow** component of Market Flows.

The remainders of Market Flows, therefore, are non-firm. When the values of these flows are known, they can be treated as equivalent to non-firm transmission service. As such, Reliability Coordinators can request Market-Based Operating Entities provide relief under TLR based on these transmission priorities.

By applying the above philosophy to the problem of coordinating congestion management, we can determine not only the impacts of a Market-Based Operating Entity's dispatch on a particular Flowgate, we can also determine the appropriate firmness of those flows. This results in the ability to coordinate both proactive and reactive congestion management between operating entities in a way that respects the current TLR process, while still allowing for the flexibility of internal congestion management based on Locational Marginal Pricing.

There are two areas that must be defined in order for this process to work effectively:

- **Coordinated Flowgate Definition.** In order to ensure that impacts of dispatch are properly recognized, a list of Flowgates must be developed around which congestion management may be effected and coordination can be established.
- **Congestion Management.** By coordinating congestion management efforts and enhancing the TLR process to recognize both untagged internal flows and data of finer granularity, we can ensure that when TLR is called, the appropriate non-Firm Flows are reduced before Firm Flows. This will result in a reduction of TLR 5 events, as more relief will be available in TLR 3 to mitigate a constraint. We will accomplish this through the calculation of flows due to Economic Dispatch, as well as by providing Marginal Unit information to aid in Interchange transaction management.

The next sections of this document discuss each of these areas in detail.

Section 3 - Impacted Flowgate Determination

Flowgates

Flowgates are facilities or groups of facilities that may act as significant constraint points on the system. As such, they are typically used to analyze or monitor the effects of power flows on the bulk transmission grid. Operating Entities utilize Flowgates in various capacities to coordinate operations and manage reliability. For this purposes of this process, there are two kinds of Flowgates: Coordinated Flowgates, which are defined below, and Reciprocal Coordinated Flowgates, which are defined in Section 6. A diagram illustrating how these two categories of Flowgates are determined is included as Appendix M.

Coordinated Flowgates

An Operating Entity will conduct sensitivity studies to determine which Flowgates are significantly impacted by the Market Flows of the Operating Entity's Control Zones (currently the Control Areas that exist today in the IDC). An Operating Entity identifies these Flowgates by performing the following four studies to determine which Flowgates the Operating Entity will monitor and help control. A Flowgate passing any one of these studies will be considered a **Coordinated Flowgate (CF)**.

An Operating Entity may also specify additional Flowgates that have not passed any of the four studies to be Coordinated Flowgates. For Flowgates on which the Operating Entity expects to utilize the TLR process to protect system reliability, such specification is required. For a list of Coordinated Flowgates between PJM and MISO, please see Appendix F.

Coordinated Flowgates are defined to determine which Flowgates an entity impacts significantly. This set of Flowgates may then be used in the Congestion Management processes and/or Reciprocal Operations defined in this document.

PJM and MISO will work with NERC and the TLR history to further validate this list of proposed Flowgates. PJM and MISO will also implement the rulings of the Michigan/Wisconsin Hold Harmless proceedings. This list will be reviewed by various Regional and NERC Committees (ORS/OC) to ensure its appropriateness. Use of a 5% threshold in the studies may not capture all Flowgates that experience a significant impact due to market operations. The Operating Entities have agreed to adopt a lower threshold at the time NERC implements the use of a lower threshold in the TLR process.

Study 1) – IDC Base Case

(using the IDC tool)

The IDC can provide a list of Flowgates for any user-specified Control Area whose GLDF (Generator to Load Distribution Factor (NNL)) impact is 5% or greater. The Operating Entity will use the IDC capabilities to develop a preliminary set of Flowgates. This list will contain Flowgates that are impacted by 5% or greater by the Control Areas that will be joining the Operating Entity as Control Zones/areas. Using the present Control Area representation in the IDC (i.e., pre-Operating Entity expansion), if any one generator has a GLDF (Generator to Load Distribution Factor) greater than 5% as determined by the IDC, this Flowgate will be considered a Coordinated Flowgate.

As an example, consider the PTDF Flowgate #3301:

Flowgate #3301 - Tazewell-Mason 138 kV line

This Flowgate is located in the Central Illinois Light Company Control Area, which is in the MISO Operating Entity. The GLDFs obtained from the IDC indicate that there are two units in the Com-Ed Control Area that have a GLDF greater than 5%. Com-Ed is joining the PJM Operating Entity.

Although there are about 150 generators in the Com-Ed area that do not have a GLDF greater than 5% (and some units which have a negative GLDF), the fact that there is at least one generator with a GLDF greater than 5% qualifies this Flowgate for inclusion in the PJM Operating Entity list of Coordinated Flowgates that PJM will respect.

Study 2) – IDC PSS/E Base Case

(no transmission outages – offline study)

In order to confirm the IDC analysis, and to provide a better confidence that the Operating Entity has effectively captured the subset of Flowgates upon which its generators have a significant impact, an offline study utilizing MUST capabilities will be conducted. The Operating Entity will perform off-line studies (using the IDC PSS/E base case) to confirm the IDC analysis.

Study 3) – IDC PSS/E Base Case

(transmission outage - offline study)

In order to determine outage conditions (if any) that may cause the Operating Entity's Control Zones/areas to have a significant impact on Flowgates, the Operating Entity will perform 2nd contingency (n-2) analysis, including both internal and external outages. This study will be performed offline utilizing MUST capabilities. If any additional

Flowgates are found using this method, and they represent a 3% or greater impact when reexamined under Study 1 or 4, they will be added to the list of Coordinated Flowgates.

Study 4) – Control Area to Control Area

For those situations where one or more Control Areas are being incorporated into a market footprint, there will be a Flowgate analysis performed to determine which Flowgates impacted by those Control Areas will be included in the list of Coordinated Flowgates. The Operating Entity will analyze transactions between each CA and the existing market, as well as between each CA/CA permutation (if more than one CA is moving into the market). This study will use Transfer Distribution Factors (TDFs) from the IDC and offline studies utilizing MUST capabilities. Flowgates that are impacted by greater than 5% as determined by the IDC will be considered a Coordinated Flowgate.

Disputed Flowgates

If a Reliability Coordinator (RC) believes that a Market-Based Operating Entity implementing the congestion management portion of this process has a significant impact on one of their Flowgates, but that Flowgate was not included in the Coordinated Flowgate list, the following process will be followed by the involved parties.

The RC conducts studies to determine the conditions under which a Market-Based Operating Entity's Market Flows would have a significant impact on the Flowgate in question. The RC then submits these studies to the Market-Based Operating Entities implementing this process. The RC's studies should include each of the four studies described above, in addition to any other studies they believe illustrate the validity of their request. The Market-Based Operating Entities will review the studies and determine if they appear to support the request of the RC. If they do, the Flowgate will be added to the list of Coordinated Flowgates.

If, following evaluation of the supplied studies, any Market-Based Operating Entity still disputes the RC's request, the RC will submit a formal request to the NERC Operations Reliability Subcommittee (ORS) asking for further review of the situation. The ORS will review the studies of both the requesting RC and the Market-Based Operating Entities, and direct the participating Market-Based Operating Entities to take appropriate action.

Third Party Request Flowgate Additions

Each party shall provide in its stakeholder processes opportunities for third parties or other entities to propose additional Coordinated Flowgates and procedures for review of relevant non-confidential data in order to assess the merit of the proposal.

Dynamic Creation of Flowgates

For temporary Flowgates developed "on the fly," the IDC will utilize the current IDC methodology for determining NNL contribution until the Market-Based Operating Entity has begun reporting data for the new Flowgate. Interchange transactions into, out of, or across the Market-Based Operating Entity will continue to be E-tagged and available for curtailment in TLR 3, 4, or 5. Market-Based Operating Entities will endeavor to study the Flowgate in a timely manner and begin reporting Flowgate data within no more than two business days. This will ensure that the Market-Based Operating Entity has the time necessary to properly study the Flowgate using the four studies detailed earlier in this document and determine the Flowgates relationship with the Market-Based Operating Entity's dispatch (based on the studies above). For Flowgates internal to MISO or PJM, the Market-Based Operating Entity will redispatch during a TLR 3 to manage the constraint as necessary until the RTO begins reporting the 7-FN, 6-NN, and 2-NH components; during a TLR 5, the IDC will request NNL relief in the same manner as today. Alternatively, MISO or PJM may utilize an appropriate substitute internal Coordinated Flowgate that has similar internal and external impacts as the temporary Flowgate. In this case, PJM or MISO would have to realize relief through redispatch and TLR 3. An example of an appropriate substitute would be a Flowgate with a monitored element directly in series with a temporary Flowgates monitored element and with the same contingent element.

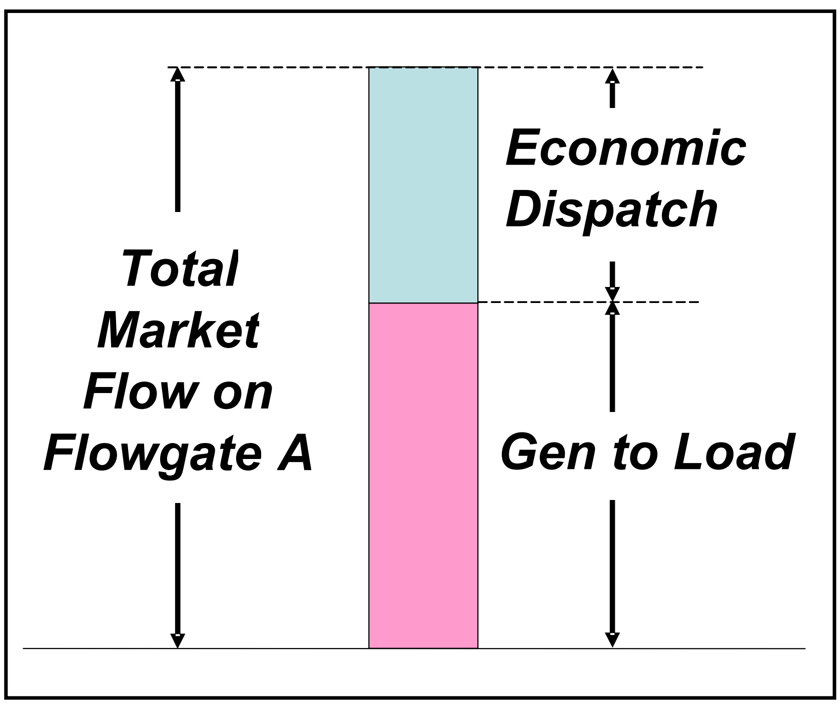
If the Flowgate meets the necessary criteria, the Market-Based Operating Entity will begin to provide the necessary values to the IDC in the same manner as Market Flows and Firm Gen-to-Load Flow values are provided to the IDC for all other Coordinated Flowgates. If in the event of a system emergency (TLR 3b or higher) and the situation requires a response faster than the process may provide, the Market-Based Operating Entity's will coordinate respective actions to provide immediate relief until final review.

Note that the requirements for Market-Based Operating Entities only apply to MISO at the point at which they begin operating their market. Until that time, MISO will only be performing reciprocal operations on these Flowgates.

The present functionality of PJM's and MISO's real-time Security Analysis programs allows for the creation and activation of new contingencies or Flowgates in real-time within a matter of minutes. Data set builds or uploads are not necessary to add a new contingency or Flowgate to these real-time monitoring and control applications. With the Flowgate now included in the real-time system, PJM and MISO can then redispatch effective internal generation to provide the required/requested relief exactly as will be done for all other Coordinated Flowgates.

Section 4 - Market-Based Operating Entity Flow Calculations: Market Flow, Firm Gen-to-Load Flow, and Economic Dispatch

When a Market-Based Operating Entity's dispatch creates flows on a Coordinated Flowgate, those flows can be quantified and considered the directional **Market Flow.** Market Flow is then further designated into two components: **Firm Gen-to-Load Flow,** which is energy flow related to contributions from the Network Native Load serving aspects of the dispatch, and **Economic Dispatch (ED) Flow,** which is energy flow related to the Market-Based Operating Entity's market operations. These distinctions are important, as the Firm Gen-to-Load Flows are considered firm, while the Economic Dispatch Flows are not.



Each Market-Based Operating Entity will calculate their actual real-time and projected directional Market Flows, as well as their directional Firm Gen-to-Load Flows, on each

Coordinated Flowgate. These values will allow the Market-Based Operating Entity to determine the Economic Dispatch (ED) Flows created by the markets operations. The following sections outline how these flows will be computed.

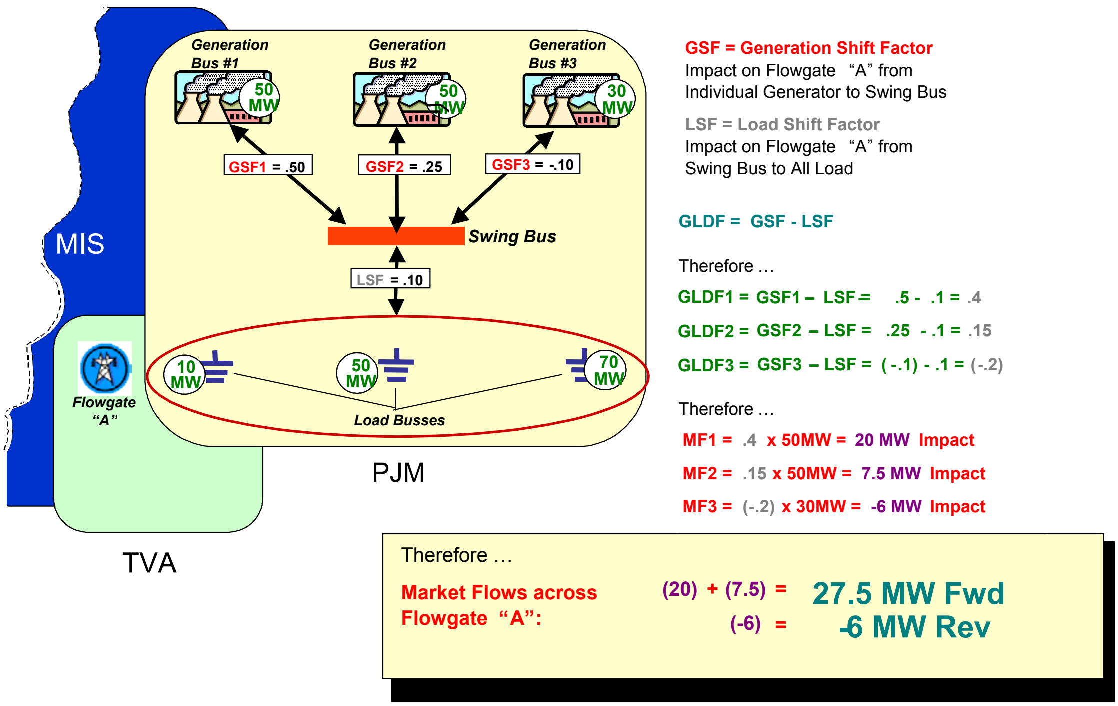
Market Flow Determination

The determination of Market Flows builds on the "Per Generator" methodologies that were developed by the NERC Parallel Flow Task Force. The "Per Generator Method Without Counter Flow" was presented to and approved by both the NERC Security Coordinator Subcommittee (SCS) and the Market Interface Committee (MIC). [1] This methodology is presently used in the IDC to determine NNL contributions.
Similar to the Per Generator Method, the Market Flow calculation method is based on Generator Shift Factors (GSFs) of a market area's assigned generation and the Load Shift Factors (LSFs) of its load on a specific Flowgate, relative to a system swing bus. The GSFs are calculated from a single bus location in the base case (e.g. the terminal bus of each generator) while the LSFs are defined as a general scaling of the market area's load. The Generator to Load Distribution Factor (GLDF) is determined through superposition by subtracting the LSF from the GSF.

The determination of the Market Flow contribution of a unit to a specific Flowgate is the product of the generator's GLDF multiplied by the actual output (in megawatts) of that generator. The total Market Flow on a specific Flowgate is calculated in each direction; forward Market Flows is the sum of the positive Market Flow contributions of each generator within the market area, while reverse Market Flow is the sum of the negative Market Flow contributions of each generator within the market area.

[1] "Parallel Flow Calculation Procedure Reference Document," NERC Operating Manual. 11 Feb, 2003. <http://www.nerc.com/~oc/opermanl.html>

Calculating the Market Flow Illustration



The Market Flow calculation differs from the Per Generator method in the following ways:

- The contribution from all market area generators will be taken into account.
- In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The Market Flow calculations will use all flows, in both directions, down to 0% with no threshold. Forward flows and reverse flows are determined as discrete values.
- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the Market Flow calculation evolves into a methodology very similar the "Per Generator Method," while providing granularity on the order of the most granular method developed by the IDC Granularity Task Force.

Directional flows are required for this process to ensure a Market-Based Operating Entity can effectively select the most effective generation pattern to control the flows on both internal and external constraints, but are considered as distinct directional flows to ensure comparability with existing NERC TLR processes. Under this process, the use of real-time values in concert with the Market Flow calculation effectively implements one of the more accurate and detailed method of the six IDC Granularity Options considered by the NERC IDC Granularity Task Force

Units assigned to serve a market area's load do not need to reside within the market area's footprint to be considered in the Market Flow calculation. However, units outside of the market area will not be considered when those units will have tags associated with their transfers.

Additionally, there may be situations where the participation of a generator in the market may be less than 100% (e.g., a unit jointly owned in which not all of the owners are participating in the market). Such situations will need to be recognized and accounted for in the market's operations.

Finally, imports into or exports out of the market area, and tagged grandfathered transactions within the market area, must be properly accounted for in the determination of Market Flows. When the actual generation of the market area exceeds the total load of that area, the market area is exporting energy. These exports are tagged transactions that must be accounted for in the Market Flow calculation. This will be accomplished within the calculation by including a new term that offsets the MW output of the marginal unit(s) by the amount of the net market export. This ensures that the Market Flow calculation is measuring only the effect of internal generation serving internal load.

When the actual generation of the market area is less than the total load of the market area, that area is importing energy. These imports are tagged transactions that are inherently not included in the determination of Market Flows, as "Market Flows" are a measure of internal generation serving internal load. The processes currently within IDC will address the counting of these transactions.

Below is a summary of the calculations discussed above.

For a specified Flowgate, the Market Flow impact of a market area is given as:

Total Directional "Market Flows" = ∑ (Directional "Market Flow" contribution of each unit in the LMP area), grouped by impact direction

where,

"Market Flow" contribution of each unit in the LMP area =

(GLDF) (Real-Time generator output) (Participation Percent/100)

and,

GLDF is the Generator to Load Distribution Factor

Real-Time generator output* is the present MW level of the generator

Participation Percent is the share of the unit participating in the LMP area's market

(* if the RTO is a net exporter at the time of the calculation, the output level of the marginal unit(s) has been reduced by this export value)

The real-time and projected "Market Flows" will be calculated on-line utilizing the LMP area's state estimator model and solution. This is the same solution presently used to determine real-time LMPs as well as providing on-line reliability assessment and the periodicity of the Market Flow calculation will be on the same order. Inputs to the state estimator solution include the topology of the transmission system and actual analog values (e.g., line flows, transformer flows, etc…). This information is provided to the state estimator automatically via SCADA systems such as NERC's ISN link.

Using an on-line state estimator model to calculate "Market Flows" provides a more accurate assessment than using an off-line representation for a number of reasons. The calculation incorporates a significant amount of real-time data, including:

- **Actual real-time and projected generator output.** Off-line models often assume an output level based on a nominal value (such as unit maximum capability), but there is no guarantee that the unit will be operating at that assumed level, or even on-line. Off-line models may not reflect the impact of pumped-storage units when in pumping mode; these units may be represented as a generator even when pumping. A real-time calculation explicitly represents the actual operating modes of these units.
- **Actual real-time bus loads.** Off-line assessments may not be able to accurately account for changes in load diversity. Off-line models are often based on seasonal winter and summer peak load base cases. While representative of these peak periods, these cases may not reflect the load diversity that exists during off-peak and shoulder hours as well as off-peak and shoulder months. A real-time calculation explicitly accounts for load diversity. Off-line assessments may also reflect load reduction programs that are only in effect during peak periods.
- **Actual real-time breaker status.** Off-line assessments are often bus models, where individual circuit breakers are not represented. On-line models are typically node models where switching devices are explicitly represented. This allows for the real-time calculation to automatically account for split bus conditions and unusual topology conditions due to circuit breaker outages.

Additionally, the calculation rate of the on-line assessment is much quicker and accurate than an off-line assessment, as the on-line assessment immediately incorporates changes in system topology and generators. Facility trippings and outages are automatically incorporated into the real-time assessment.

In order to provide reliable and consistent flow calculations, entities utilizing this process as the basis for coordination must ensure that the modeling data and assumptions used in the calculation process are consistent. PJM and MISO will coordinate models to ensure similar computations and analysis. PJM and MISO will each utilize real-time ICCP and ISN data for observable areas in each of their respective state estimator models and will utilize NERC data for areas outside the observable areas to ensure their models stay synchronized with each other and the NERC IDC.

Firm Gen-to-Load Flow Determination Overview

Firm Gen-to-Load Flows represent the directional sum of designated network resources serving designated network loads within a particular market area. They are based primarily on the configuration of the system and its associated flow characteristics; utilizing generation and load values as its primary inputs. Therefore, these Firm Gen-to-Load Flows can be determined based on expected usage and the Allocation of Flowgate capacity.

An entity can determine firm network service flows on a particular Flowgate using the same process as utilized by the IDC. This process is summarized below:

1. Utilize a base case to determine the Generation Shift Factors for all generators in the current Control Areas' respective footprints to a specific swing bus with respect to a specific Flowgate.
2. Utilize the same base case to determine the Load Shift Factors for the Control Areas load to a specific swing bus with respect to that Flowgate.
3. Utilize superposition to calculate the Generation to Load Distribution Factors (GLDF) for generator with respect to that Flowgate.
4. Multiply the expected output used to serve native load from generator by the appropriate GLDF to determine that generators flow on the Flowgate.
5. Sum these individual contributions by direction to create the directional firm network service impact on the Flowgate.

PJM and MISO will utilize the IDC Base Case (or other mutually agreed upon Base case) as the reference base case for these calculations.

Determining the Firm Gen-to-Load Limit

Given the Firm Gen-to-Load Flow determinations, Market-Based Operating Entities can assume them to be their **Firm Gen-to-Load Limits.** These limits defines the maximum value of their Market Flows that can be considered as Firm in each direction on a particular Flowgate. One day prior to real time, a calculation will be done based on updated hourly forecasted loads and topology. The results should be an hourly forecast of directional Firm Gen-to-Load Flows. This is a significant improvement over current IDC processes, which uses a peak load value instead of an hourly load more closely aligned with forecasted data.

PJM and MISO have agreed to several rules for determining Firm Gen-to-Load Flows. These rules are based on the rules used by the IDC, and can be found in later in this Section.

Firm Gen-to-Load Calculation Rules

The Firm Gen-to-Load Limits will be calculated based on certain criteria and rules. The calculation will include the effects of firm network service in both forward and reverse directions. The process will be similar to that of the IDC (but utilizing impacts down to 0%). The following points form the basis for the calculation.

Firm Network Service

1. The generation-to-load calculation will be made on a control-area basis. The impact of generation-to-load will be determined for Coordinated Flowgates.
2. The Flowgate impact will be determined based on individual generators serving aggregated CA load. Only generators that are designated network resources for the CA load will be included in the calculation.
3. All impacts on the Flowgate will be considered, including impacts of less than 5%.
4. Designated network resources located outside the CA will not be included in the generation-to-load calculation if OASIS reservations exist for these generators.
5. If a generator or a portion of a generator is used to make off-system sales that have an OASIS reservation, that generator or portion of a generator should be excluded from the generation-to-load calculation.
6. Generators that will be off-line during the calculated period will not be included in the generation-to-load calculation for that period.
7. CA net interchange will be computed by summing all firm PTP reservations and all designated network resources that are in effect throughout the calculation period. Designated network resources are included in CA net interchange to the extent they are located outside the CA and have an OASIS reservation. The net

interchange will either be positive (exports exceed imports) or negative (imports exceed exports).

8. If the net interchange is negative, the period load is reduced by the net interchange.
9. If the net interchange is positive, the period load is not adjusted for net interchange.
10. The generation-to-load calculation will be made using generation-to-load distribution factors that represent the topology of the system for the period under consideration.
11. PMAX of the generators should be net generation (excluding the plant auxiliaries) and the CA load should not include plant auxiliaries.
12. The portion of JOUs that are treated as schedules will not be included in the generation-to-load calculation if an OASIS reservation exists.

Section 5 - Market-Based Operating Entity Congestion Management

Once there has been an establishment of the Firm Gen-to-Load Limit that is possible given Firm Gen-to-Load Flow calculation, we can move into operations and utilize that data in a manner that relates to real time energy flows.

Calculating Market Flows

On a periodic basis, the Market-Based Operating Entity will calculate directional Market Flows for all Coordinated Flowgates. These flows will represent the actual flows in each direction at the time of the calculation, and be used in concert with the previously calculated Firm Gen-to-Load Limits to determine the portion of those flows that should be considered firm and non-firm.

Providing Data for Reliability Analysis

Every fifteen minutes, the Market-Based Operating Entity will be responsible for providing to Reliability Coordinators the following information:

- Firm Gen-to-Load Flows for all Coordinated Flowgates in each direction
- Economic Dispatch Flows for all Coordinated Flowgates in each direction

The Firm Gen-to-Load Flow (Priority 7-FN) will be equivalent to the calculated Market Flow, up to the Firm Gen-to-Load Limit. Any Market Flow in excess of the Firm Gen-to-Load Limit will be reported as Economic Dispatch (Priority 6-NN) (note that under reciprocal operations, some of this Economic Dispatch may be quantified as Priority 2-NH).

This information will be provided for both current hour and next hour, and is used in order to communicate to Reliability Coordinators the amount of flows to be considered firm service on the various Coordinated Flowgates in each direction. When Firm Gen-to-Load Limit forecast is calculated to be greater than Market Flow for current hour or next hour, actual Firm Gen-to-Load Limit (used in TLR5) will be set equal to Market Flow.

Additionally, every hour the Market-Based Operating Entity will submit to the Reliability Authority a set of data describing the marginal units and associated participation factors for generation within the market footprint. The level of detail of the data may vary, as different Operating Entities will have different unique situations to address. However, this data will at a minimum be supplied for imports to and exports from the market area, and will contain as much information as is determined to be necessary to ensure system reliability. This data will be used by the Reliability Authority to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

Day-Ahead Operations Process

The Market-Based Operating Entity executes a day-ahead unit commitment for all of the generators throughout the market footprint. PJM's and MISO's day ahead unit commitment uses a network analysis model that mirrors the real-time model found within their state estimators. As such, the day-ahead commitment respects facility limits and forecasted system constraints.

Real-time Operations Process

Operating Entity Capabilities

PJM's and MISO's real-time EMSs have very detailed state estimator and security analysis packages that are able to monitor both thermal and voltage contingencies every few minutes. State estimation models will be at least as detailed as the IDC model for all the Coordinated and Reciprocal Coordinated Flowgates. Additionally, PJM, MISO, and OATI will be continually working to ensure model synchronization. PJM and MISO will also initiate similar coordination whenever the IDC model is updated. The data PJM and MISO will utilize in its model will be either over ICCP links or over the NERC ISN.

The PJM and MISO state estimators and the Unit Dispatch Systems (UDS) will utilize all of these real-time internal flows and generator outputs to calculate both the actual and projected hour ahead flows (i.e., total Market Flows, Economic Dispatch, and Firm Gen-to-Load Limit) on all of the Coordinated Flowgates. Using real-time modeling, the PJM and MISO internal systems will be able to more reliably determine the impact on Flowgates created by dispatch than the NERC IDC. The reason for this difference in accuracy is that the IDC uses very static SDX data that models generators as either at full output or off. In contrast, PJM's and MISO's calculations of system flows will utilize each unit's actual output, updated every at least every 15 minutes on an established schedule.

Operating Entity Real-time Actions

Market-Based Operating Entities will have the list of Coordinated Flowgates modeled as monitored facilities in its EMS. The Firm limits a Market Based Operating Entity will use for these third party Flowgates will be the Firm Gen-to-Load Limits determined by the Firm Gen-to-Load Flow calculations.

The Market-Based Operating Entity will upload the real-time and projected Firm (7-FN) and Non-Firm (6-NN) flows on these Flowgates to the IDC every 15 minutes, as requested by the NERC IDCWG and OATI (note that under reciprocal operations, some of this 6-NN may be quantified as Priority 2-NH). When the real time actual or projected flows exceed these Firm Gen-to-Load Flow values on a Flowgate and the Reliability Coordinator who has responsibility for that Flowgate has declared a TLR 3a or higher, the Market-Based Operating Entity will redispatch its system to the amount required by the IDC. The amount of redispatch will be calculated by the IDC. In a TLR 3, the Market-Based Operating Entity could be required to redispatch to the full amount of economic dispatch over the Firm Gen-to-Load Limit. Note the Market-Based Operating Entity may provide relief through either 1.) a reduction of flows on the Flowgate in the direction required, or 2.) an increase of reverse flows on the Flowgate.

Market-Based Operating Entities will implement this redispatch by binding the Flowgate as a constraint in their Unit Dispatch System (UDS). UDS calculates the most economic solution while simultaneously ensuring that each of the bound constraints is resolved reliably. Additionally, the Market-Based Operating Entity will make any point-to-point transaction curtailments as specified by the NERC IDC.

PJM's and MISO's redispatch/relief will be faster than the 30 minutes required by TLR schedule curtailments, because when the bounds are applied, the systems are designed to provide relief within 15 minutes.

The RC calling the TLR will be able to see the relief provided on the Flowgate as the Market-Based Operating Entity continues to upload their contributions to the real-time flows on this Flowgate.

Section 6 - Reciprocal Operations

PJM and the Midwest ISO intend to be the first entities to implement this plan. Further, PJM and MISO will augment the plan with the creation of reciprocal coordination agreements. These agreements will go beyond the previously discussed processes to ensure better coordination between entities. The sections following provide detail regarding PJM's and MISO's agreed to calculation procedures and reciprocal coordination practices.

Reciprocal Agreements can be executed on a market-to-market basis, a market-to-non-market basis, and a non-market-to-non-market basis. While the Congestion Management portions of this document are intended to apply specifically to Market-Based Operating Entities, the agreement to allocate Flowgate capability is not dependent on an entity operating a centralized energy market. Rather, it simply requires that a set of Flowgates be defined upon which coordination shall occur and an agreement to perform such coordination.

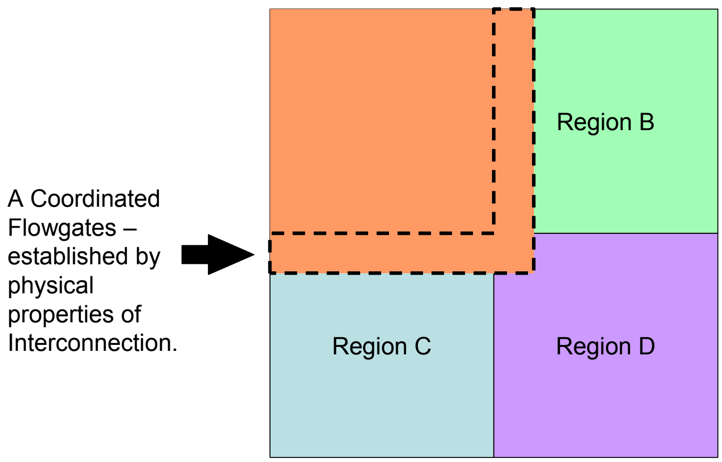
Reciprocal Coordinated Flowgates

In order to coordinate congestion management on a proactive basis, Operating Entities may agree to respect each other's Flowgate limitations during the determination of AFC/ATC and the calculation of firmness (Firm, Non-Firm Network, Non-Firm Hourly) during real-time operations. Entities agreeing to coordinate this future-looking management of Flowgate capacity are **Reciprocal Entities.** The Flowgates used in that process are **Reciprocal Coordinated Flowgates (RCFs).**

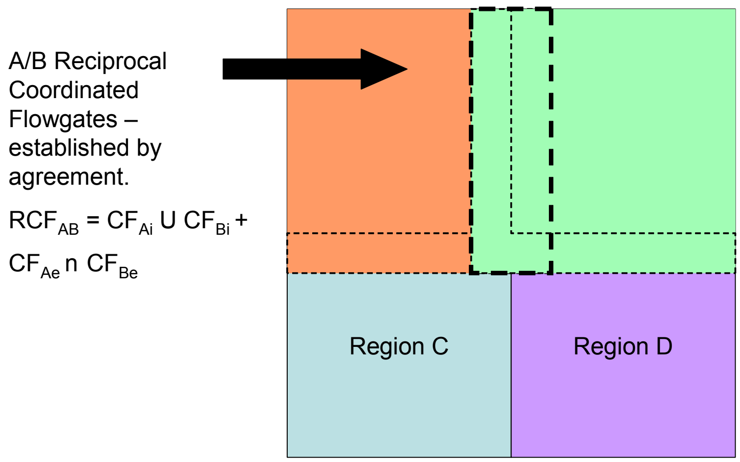
The Relationship Between CFs and RCFs

Coordinated Flowgates are associated with a specific entity's operation sphere of influence. Reciprocal Coordinated Flowgates are associated with the implementation of a reciprocal coordination agreement between two entities. When considering an implementation between two Market-Based Operating Entities, it is generally expected that the set of Reciprocal Coordinated Flowgates will be the mathematical intersection of the two entities Coordinated Flowgates.

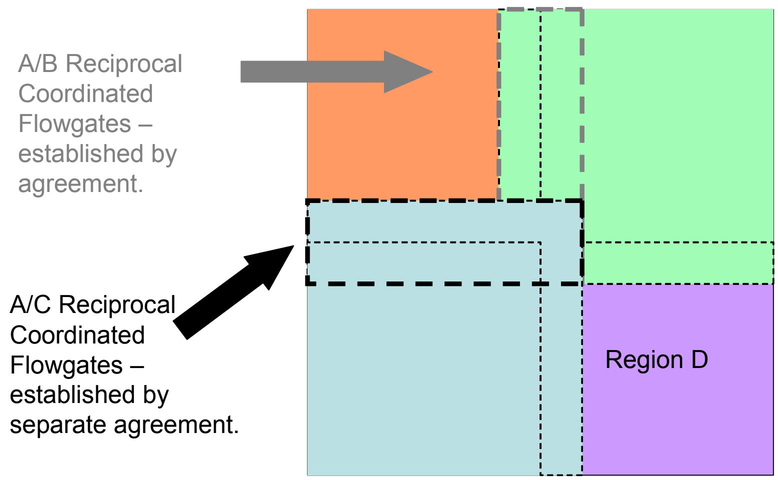
In the example below, there are four entities. The translucent red area represents the set of Coordinated Flowgates for market area A. Note that each area has it's own potential set of Coordinated Flowgates. As indicated, this set of Coordinated Flowgates is based only on the area's impact on Flowgates, not on coordination agreements. Market area A will report information to the IDC for these Flowgates to aid in curtailment procedures, but is not required to engage in any other coordination efforts (e.g., AFC Coordination, Firm Flow Allocation, etc…).



In the next example, note that both A and B have established their set of Coordinated Flowgates. A subset of the union of these sets of Flowgates establishes a baseline where reciprocal coordination can occur. This subset will include the union of all Coordinated Flowgates internal to the reciprocal entities and the intersection of all Coordinated Flowgates external to the reciprocal entities. If A and B choose to execute a reciprocal coordination agreement, the area bounded by the heavy line will become the set of Reciprocal Coordinated Flowgates. There are no coordination agreements with C and D.



If C wished to enter into a reciprocal coordination agreement with A, C would have to first establish their own set of Coordinated Flowgates. Following this, they would identify the set of Reciprocal Coordinated Flowgates, then agree to coordinate operations based on the Flowgates contained in that that set



In the last example, we illustrate a fully coordinated set of entities and the agreements that would need to be established with each entity respecting each others impacted Flowgates.

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Full Reciprocal Coordination. Reciprocal Coordination areas as follows:

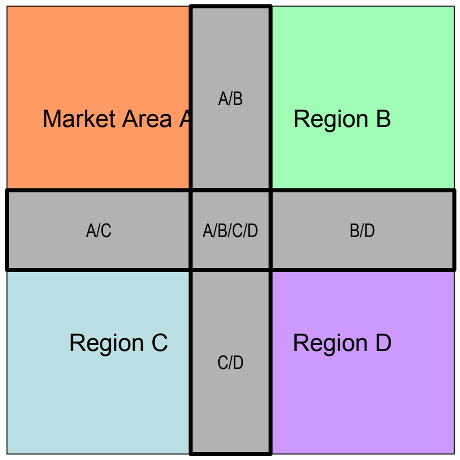
A/B (2 party)

A/C (2 party)

A/B/C/D (4 party)

B/D (2 party)

C/D (2 party)



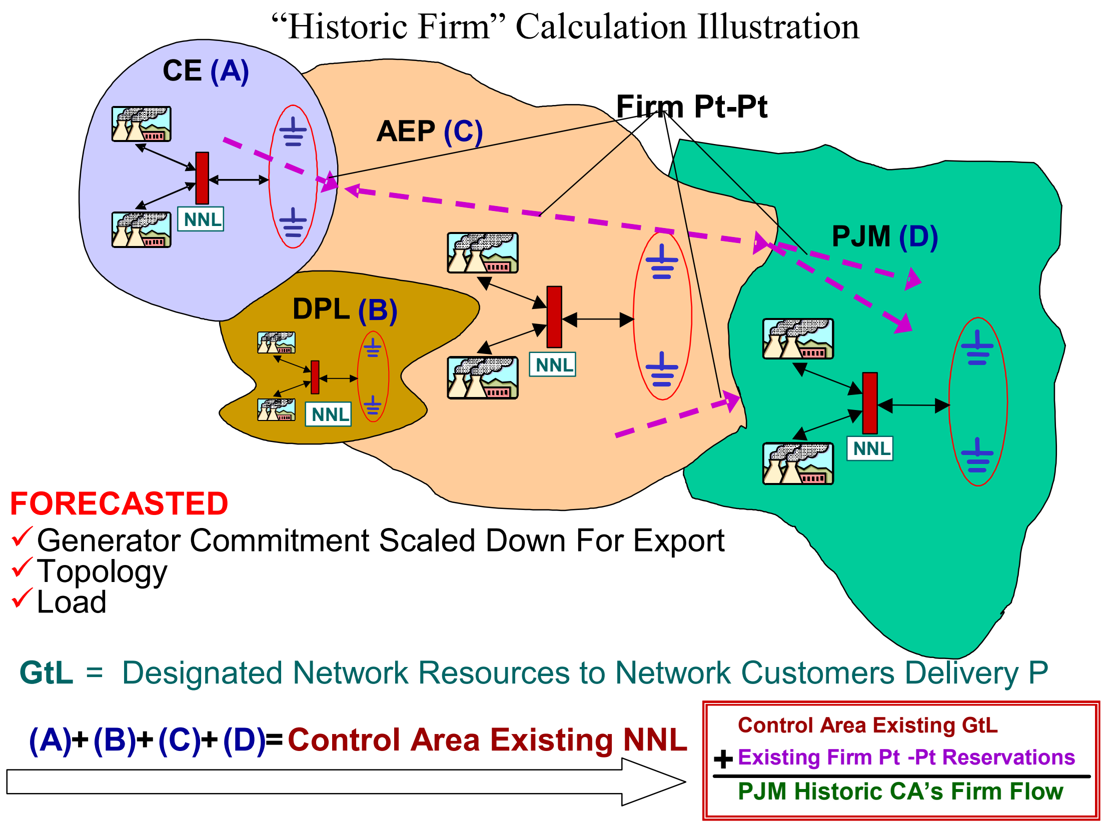
To the extent that entities other than Market-Based Operating Entities wish to enter into a reciprocal agreement, they may offer to coordinate on Flowgates that are Coordinated Flowgates (i.e., have passed one of the four tests defined within this document or otherwise been deemed to be a Coordinated Flowgate).

Coordination Process for Reciprocal Flowgates

PJM and MISO have established and finalized the following process and timing for coordinating the ATC/AFC calculations and Firm Flow Limit calculations/Allocations. Further, the process quantifies and limits Priority 6 – NN service on the RCFs, as well as determines priority 2-NH service. It is expected each of the Reciprocal Entities will require a Tariff change and filing to FERC in order to implement this process. All reciprocal entities Firm Flow Limits will be calculated on the same basis.

Calculating Historic Firm Flows

As a starting point for identifying Allocations, an understanding must be developed of what Firm Flows would be in the existing Control Area structure. In other words, the Firm Flow values that would have occurred if all Control Areas maintained their current configuration and continued to serve their native load with their generation can be identified. This flow is referred to as **Historic Firm Flow.**



PJM and MISO have developed specific processes for ensuring reasonably accurate data is utilized in this process.

Recalculation of Initial Historic Firm Flow Values and Ratios

The Firm Point-to-Point Service and Designated Resource to customer load defined by the Historic Firm Flow calculation will be updated in the recalculation of Historic Firm Flow utilizing any new Designated Resources, updated customer loads, and new transmission facilities. The original historic Control Areas will be retained for the recalculation of Historic Firm Flow. New Designated Resources will be included in the recalculation to the extent these new Designated Resources have been arranged for the exclusive use of load within the historic Control Areas and to the extent the total impact of all Designated Resources does not exceed the historic Control Area impact of Designated Resources as of a "freeze date" (currently defined by PJM and MISO as June 3rd, 2003). Any changes to Designated Resources and/or the transmission system that increase transmission capability will be assessed in accordance with MISO/PJM AFC Coordination procedures prior to the increasing of Historic Firm Flow related to those systems.

The initial Historic Firm Flow calculated values and resulting Allocation ratios will be recalculated as seasonal cases are produced. This recalculation will utilize the same firm point-to-point reservations that were used in the initial Historic Firm Flow calculation. The same firm point-to-point reservations are used so that market-operating entities that have their firm point-to-point internalized, grant fewer internal firm service reservations, or have their original firm reservations end, because of their market operations, will retain at least the same level of firm point-to-point as in the initial Historic Firm Flow calculation. Therefore, the firm point-to-point component of the Historic Firm Flow will be frozen on a "freeze date" (currently defined by PJM and MISO as June 3rd, 2003) at the initially calculated level for both market and non-market entities.

Any new Control Areas that are added to the Firm Flow calculation process for either PJM, MISO, or another Operating Entity, will use firm point-to-point reservations from the initial Historic Firm Flow calculation date to establish their firm point-to-point component of the Historic Firm Flow.

MISO and PJM will utilize this recalculation process until it is replaced by another process. It is anticipated that an enhanced, market-to-market, process will be developed to replace the Historic Firm Flow calculation process. The enhanced process may use a simultaneous deliverability type analysis rather than the Historic Firm Flow calculation process. MISO and PJM will update their respective Reliability Plans incorporating the new process and have them approved by NERC before the new process to quantify Firm Flow is implemented.

Forward Coordination Processes

1.) For each Reciprocal Coordinated Flowgate, a manager and an owner will be defined. The manager will be responsible for all calculations regarding that Flowgate; the owner will define the set of point-to-point reservations to be utilized when determining point-to-point impacts on that Flowgate.
2.) Managing entities will estimate both Gen-to-Load Firm Impacts and Point-to-Point Firm Impacts for all entities. These impacts will be used to define the Historic Ratio and the Allocation of transmission capability.
3.) The Managing entity will utilize the current NERC IDC Base Case (or other mutually agreeable Base Case) to determine impacts. The case should be

transformed with the most current set of outage data for the time period being calculated.

4.) Managing entities will calculate Allocations on the following schedule:

Allocation Run Type	Allocation Process Start	Range Allocated	Allocation Process Complete	CBM/TRM/Limit Change Lockout
April Seasonal Firm	Every April 1 at 8:00 EST	Twelve monthly values from October 1 of the current year through September 30 of the next year	April 1 at 12:00 EST	April 1 8:00 – 12:00 EST
October Seasonal Firm	Every October 1 at 8:00 EST	Twelve monthly values from April 1 of next year through March 31 of the following year	October 1 at 12:00 EST	October 1 8:00 – 12:00 EST
Monthly Firm	Every month on the second day of the month at 8:00 EST	Six monthly values for the next six successive months	2nd of the month at 12:00 EST	2nd of the month 8:00 – 12:00 EST
Weekly Firm	Every Monday at 8:00 EST	Seven daily values for the next Monday through Sunday	Monday at 12:00 EST	Monday 8:00 – 12:00 EST
Two-Day Ahead Firm	Every Day at 17:00 EST	One daily value for the day after tomorrow	Current Day at 18:00 EST	Current Day 17:00 – 18:00 EST
Day Ahead Non-Firm	Every Day at 8:00 EST	Twenty-four hourly values for the next 24-hour period (Next Day HE1-HE24 EST)	Current Day at 9:00 EST	Current Day 8:00 – 9:00 EST

5.) Historic Ratios are defined during the seasonal runs the first time an impact is calculated. For example, the 2004 April Seasonal Firm run would define the Historic Ratio for April 2005 – September 2005 (October through March would have been calculated during the 2003 October Seasonal Firm run). The Historic Ratio is based on the total impacts of the reciprocal entity on the Flowgate (Gen-to-Load Flows and Point-to-Point flows, down to 0%) relative to the total impacts of all other reciprocal entities' impacts on the Flowgate. For example, if PJM had a 30MW impact on the Flowgate and MISO had a 70MW impact on the Flowgate, the Historic Ratios would be 30% and 70%, respectively.

6.) The same rules defined in the "Congestion Management" section of this document for use in determining Gen–to-Load impacts (NNL) shall apply when performing Allocations

7.) Additional rules to be used when considering Point-to-Point impacts are defined later within this section.

8.) For each Firm Allocation run described above, the managing entity will take the following steps for each of the Flowgates, in both the forward and reverse direction, they are assigned to manage:

a.) Retrieve the Flowgate Limit
b.) Subtract the current CBM and TRM values (may be zero)
c.) Subtract the sum of all historically-determined Firm Flow impacts for all entities based on impacts greater than or equal to 5%
d.) If no capacity remains, entities' Firm Allocation is limited to this amount (i.e., their Firm Flow impacts from impacts of 5% or greater). If capacity does remain, it is allocated to the reciprocal entities pro-rata based on their Firm Flow impacts due to impacts less than 5% up to the total amount of their Firm Impacts due to impacts less than 5%.
e.) Any remaining capacity will be considered Firm and allocated to signatories of reciprocal agreements based on their Historic Ratio (as described in step 5).
f.) Upon completion of the Allocation process, the RTO will compare the current preliminary Allocation to the previous Allocations. For any given Flowgate, the larger of the Allocations will be considered the Allocation (i.e., an Allocation cannot decrease). Once all preliminary Allocations have been compared and the final Allocation determined, the managing entity will distribute the Allocations to the appropriate reciprocal signatories. This Allocation will consist of the Firm Gen-to-Load Limit and a portion of capability that can be used either for Point-to-Point service or additional Firm Gen-to-Load service.

9.) For the Non- Firm Allocation run described above, the managing entity will take the following steps for each of the Flowgates, in both the forward and reverse direction, they are assigned to manage:

a.) For each hour,
b.) Retrieve the Flowgate limit
c.) Subtract the current CBM and TRM values (may be zero)
d.) Subtract the sum of all hourly historically-determined Firm Flow impacts for all entities based on impacts greater than or equal to 5%
e.) Subtract the sum of all hourly historically-determined Firm Flow impacts for all reciprocal entities based on impacts less than or equal to 5%
f.) Any remaining capacity will be allocated to signatories of reciprocal agreements based on their Historic Ratio (as described in step 5).
g.) The Two-Day Ahead Firm Allocation is subtracted from the total entity Allocation (from steps D, E, and F).

a. If the result is positive, this value will be equivalent to the Priority 6-NN Allocation/limit, and the Firm Limit will the Two Day Ahead Firm Allocation.
b. If the result is negative or zero, the Priority 6-NN Allocation will be calculated by subtracting the total entity Allocation (from step G) from the Two-Day Ahead Firm Allocation. The Firm Limit will be the equivalent of the Day Ahead Firm Flow estimate.

h.) Upon completion of the Allocation process, the managing entity will distribute the Allocations to the appropriate reciprocal signatories. These Allocations will be considered Non-Firm Network service.

When a Market-Based Operating Entity is uploading Firm Gen-to-Load Flow contributions to the IDC, they will be responsible for ensuring that any Firm Allocations are properly accounted for. If Firm Allocations are used to provide additional Firm Network service, they should be included in the Firm Gen-to-Load contribution. If they are used to provide additional Firm Point-to-Point service, they should not be included in the Firm Gen-to-Load Flow contribution.

MISO, PJM, and all other entities participating in the Coordinated Process for Reciprocal Flowgates will maintain their Firm (Point to Point service and Network Designated) service and Network Non-Designated service impacts, including associated Market Flows, within their respective Firm and Priority 6 total Allocations.

Using the derived Firm Allocation value, the Market-Based Operating Entity may enter this value as a facility limit for the respective Flowgate. PJM and MISO will use this value to restrict unit scheduling for a Coordinated Flowgate when maintenance outage coordination indicates possible congestion and there is recent TLR activity on a Flowgate.

If bound, the Day-Ahead unit commitment will not permit flows to exceed this value as it selects units for this commitment.

As MISO and PJM gain more experience in this process, implement and enhance their systems to perform the Firm Flow calculations and Allocations, they may change the timing requirements for the Forward Coordination Process by mutual agreement.

Determining Point-to-Point Impacts

Additionally, Firm impacts used in the Allocation process incorporate the Firm Point-to-Point flows. Similar to the network service calculation described previously, to calculate each firm PTP transactions impact on the Flowgate, utilize the following process:

1. Utilize a base case to determine the generation shift factor for the source Control Area with respect to a specific Flowgate.
2. Utilize the same base case to determine the generation shift factor for the sink Control Area with respect to that Flowgate.
3. Utilize superposition to calculate the transmission distribution factor (TDF) for that source to sink pair with respect to that Flowgate.
4. Multiply the transactions energy transfer by the TDF to determine that transactions flow on the Flowgate.

Summing each of these impacts by direction will provide the directional firm point-to-point service impact on the Flowgate.

Combining the directional firm point-to-point service impacts with the directional firm network service impacts will provide the directional Firm Flows on the Flowgate.

Rules for considering Firm Point-to-Point Transactions

1. Firm PTP transmission service and designated network resources that have an OASIS reservation are included in the calculation.
2. A date will be selected as a freeze date (currently agreed to by MISO and PJM to be June 3rd, 2003). PJM and MISO will utilize a reference year of December 1, 2003 through November 30, 2004 for determining the confirmed set of reservations that will be used in the Allocation process. Confirmed reservations received after the freeze date will not be considered.
3. A potential for duplicate reservations exists if a transaction was made on individual CA tariffs (not a regional tariff) and both parties to the transaction (source and sink) are Reciprocal Entities. In this case, each Reciprocal Entity will receive 50% of the transaction impact.
4. To the extent a partial path reservation is known to exist, it will have 100% of its impacts considered on Reciprocal Coordinated Flowgates owned by the party that sold the partial path service and 0% of its impacts considered on other Reciprocal Coordinated Flowgates.
5. Because reservations that are totally within the footprint of the regional tariff do not have duplicate reservations, these reservations will have the full impact

considered even though both parties to the transaction (source and sink) are within the boundaries of the regional tariff and could be considered Reciprocal Entities. Similar to the firm network service calculation, the firm point-to-point service calculation:

- Will considered all reservations (including those with less than 5% impact)
- Will base response factors on the topology of the system for the period under consideration.
- In general, will not make a generation-to-load calculation where a reservation exists.

Limiting Point-to-Point Transmission Sales

The Flowgate Allocations will represent the share of total flowgate capacity (STFC) that a particular entity has been allocated. This STFC represents the maximum total impact that entity is allowed to have on that Flowgate.

In order to coordinate with the existing AFC process, it is necessary that this number be converted to an available STFC (ASTFC) which represents how much Flowgate capability remains available on that Flowgate for use as transmission service. In order to accomplish this, the entity receiving STFC will do the following:

Step	Example
1.) Start with the STFC	100
2.) Add all Forward Gen to Load Flow Impacts (down to 0%) and all Reverse Gen to Load Flow Impacts (down to 0%) to obtain the Net Gen to Load Flow Impacts. The Gen to Load Flow impacts should be based on the *best estimate* of Firm Gen-to-Load Flow for the time period being evaluated.	42 + (-20) = 22
3.) Subtract the Net Gen to Load Flow Impacts from the STFC to produce the Interim STFC	100 – 22 = 78
4.) Add all Forward Point to Point Flow Impacts (down to 0%) and 15% of all Reverse Point to Point Flow Impacts (down to 0%) to obtain the Weighted Net Point to Point Flow Impacts. The Point to Point Flow impacts should be based on the	58 + (0.15 (-45)) = 58 + (-6.75) ≈ 58 + (-7) =

current set of reservations in effect for the time period being evaluated (*not* the historic reservation set)	51
5.) Subtract the Weighted Net Point to Point Flow Impacts from the Interim STFC. The result is the ASTFC	78 – 51 = 27

This ASTFC can then be compared with the AFC calculated through traditional means.

If the AFC value is LOWER than the ASTFC value, the AFC value should be utilized as the AFC for the purpose of posting ATC and approving/denying service. In this case, while the Allocation process might indicate that the entity has rights to a particular Flowgate through the Allocation process, current conditions on that Flowgate indicate that selling those rights would result in overselling of the Flowgate, introducing a reliability problem.

If the AFC value is HIGHER than the ASFTC value, the ASTFC value should be utilized as the AFC for the purpose of posting ATC and approving/denying service. In this case, while the AFC process might indicate that the entity can sell much more service than the Allocation might indicate, the entity is bound to not sell beyond their Allocation.

Market-Based Operating Entities Providing Data for Reliability Analysis

In addition to the responsibilities described earlier in section 5 of this document, Reciprocal Market Based Operating Entities will have an additional obligation to further quantify their Non-Firm Flows into two (2) separate priorities: Non-Firm Network (6-NN) , and Non-Firm Hourly (2-NH). Priorities will be determined as follows:

1.) If the Market Flow exceeds the sum of the Firm Gen-to-Load Flow Limit and the 6-NN Allocation, then:
    2-NH = Market flow – (Firm Gen-to-Load Flow Limit + 6-NN Allocation)
    6-NN = 6-NN Allocation
    7-FN = Firm Gen-to-Load Flow Limit
2.) If the Market Flow exceeds the Firm Gen-to-Load Flow Limit but is less than the 6-NN Allocation, then:
    2-NH = 0
    6-NN = Market Flow – Firm Gen-to-Load Flow Limit
    7-FN = Firm Gen-to-Load Flow Limit

3.) If the Market Flow does not exceed the Firm Gen-to-Load Flow Limit, then
2-NH = 0
6-NN = 0
7-FN = Market Flow

All other aspects of this data remain identical to those described in Section 5.

Real-time Operations Process for Market-Based Operating Entities

Market-Based Operating Entity Capabilities

Capabilities remain as described in Section 5.

Market-Based Operating Entity Real-time Actions

Procedures remain as described in Section 5. However, as described above, additional information regarding the firmness of those Economic Dispatch Flows will be communicated as well – a portion will be reported as 6-NN, while the remainder will be reported as 2-NH. This will provide additional ability for the IDC to curtail portions of the Economic Dispatch Flows earlier in the TLR process.

Section 7 - Conclusion

PJM and MISO have worked extensively with one another and their respective stakeholders and the NERC Community to reliably address the congestion management/parallel flow seams issue identified in July of 2002.

The processes stated in this paper address each of the three complexities of this critical seams issue. Highlighted in bold are these complexities – followed by a summary of how PJM and MISO have addressed each of these concerns.

In an LMP based market there are no internal transactions to tag. A security constrained economic dispatch is used to dispatch generation for the entire region. By calculating the economic flows caused by a large market's operations, the Operating Entity is ensuring that all flows are still being accounted for both within and external to the Operating Entity. Further, the Operating Entity calculations will allow the tracing and control of flows previously not addressed within the existing tag-based system. Additionally, by using re-dispatch in conjunction with transaction curtailments, the impacting Operating Entity will be able to provide more effective and timely relief to the constrained Reliability Coordinator.

The security constrained economic dispatch does not automatically honor external system constraints. Identifying and mitigating congestion impacts due to external system influences requires a different approach than contract path and use of TLR. This process sets a new standard for external coordination. Operating Entities with expanding markets will ensure that they track and respond to the Market Flows they create over an extensive list of Coordinated Flowgates. Additionally, this process offers an option for Inter-regional AFC coordination between Operating Entities. Through coordination of transmission service and by responding to real-time flows, Operating Entities will have a new and effective way to manage parallel flows.

An effective coordination agreement between MISO and PJM is necessary to minimize the probability of Level 5 TLRs. MISO and PJM's initiative will minimize the probability of TLR 5's because far more flows are being accounted for than they have been in the past. Additionally, with changes to flow determination and tagging the IDC will be armed with far more granularity than it has in the past. This granularity will provide Reliability Coordinators far more effective processes to control flows within a TLR 3.

PJM and MISO are confident that the processes stated in this paper have addressed the MISO/PJM congestion management reliability seams issues and will greatly enhance reliable operations throughout the Eastern Interconnection.

Section 8 - Appendices

Appendix A - Glossary

Allocation – a calculated share of capability on a Reciprocal Coordinated Flowgate to be used by Reciprocal Entities when coordinating AFC, transmission sales, and dispatch of generation resources.

Control Area – an electric power system or combination of electric power systems to which an common automatic generation control scheme is applied.

Control Zones - Within an Operating Entity Control Area that is operating with a common economic dispatch, the Operating Entity footprint is divided into Control Zones to provide specific zonal regulation and operating reserve requirements in order to facilitate reliability and overall load balancing. The zones must be bounded by adequate telemetry to balance generation and load within the zone utilizing automatic generation control.

Coordinated Flowgate – Coordinated Flowgate or "CF" shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of this document. For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the Congestion Management portion of this document (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a third party.

Economic Dispatch Flow - that portion of Market Flow related to a Market Based Operating Entity's market operations in excess of that entity's Firm Gen-to-Load Flow.

Firm Flow – the estimated impacts of firm Network and Point-to-Point service on a particular Coordinated Flowgate.

Firm Flow Limit – the maximum value of Firm Flows an entity can have on a Reciprocal Coordinated Flowgate, as calculated in the reciprocal Allocation process as defined in this document.

Firm Gen-to-Load Limit - the maximum amount of Market Flows on an RCF that can be considered firm based on the reciprocal Allocation process as defined in this document.

Firm Gen-to-Load Flow - the portion of Market Flow on a Coordinated Flowgate related to contributions from the native load serving aspects of the dispatch (constrained as appropriate by the Firm Gen-to-Load Limit).

Flowgate – a representative modeling of facilities or groups of facilities that may act as significant constraint points on the regional system.

Historic Firm Flow – the estimate of impact an entity has on a Reciprocal Coordinated Flowgate when considering its historic Designated Resources and point-to-point sales that meet the "freeze date" criteria.

Historic Firm Gen-to-Load Flow – the flow associated with the native load serving aspects of dispatch that would have occurred if all Control Areas maintained their current configuration and continued to serve their native load with their generation.

Historic Ratio – the ratio of Historic Firm Flow of one reciprocal entity compared to the Historic Firm Flow of all reciprocal entities on a specific Reciprocal Coordinated Flowgate.

LMP Based System or Market - An LMP based system or market utilizes a physical, flow-based pricing system to price internal energy purchases and sales.

Locational Marginal Pricing (LMP) - the processes related to the determination of the LMP, which is the market clearing price for energy at a given location in a MBOE's market area.

Market Flows - the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources within a Market Based Operating Entity's market (excluding tagged transactions).

Market-Based Operating Entity (MBOE) – An Operating Entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.

Network and Native Load (NNL) Impact - Network and Native Load Impact is the impact of generation resources serving internal system load, based on generation the network customer designates for Network Integration Transmission Service (NITS). Also referred to as "Gen-to-Load" impact.

Operating Entity – An entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

Reciprocal Agreement - an agreement between parties to implement the reciprocal coordination procedures defined in this document.

Reciprocal Coordinated Flowgate – a Coordinated Flowgate with respect to which a Reciprocal Agreement has been written and to which reciprocal coordination procedures as defined in this document apply. A RCF is either (1) a Coordinated Flowgate affected by the transmission of energy by both parties, or (2) a Flowgate which both parties mutually agree should be a Coordinated Flowgate, and for which reciprocal coordination will occur.

Reciprocal Entity – an entity that coordinates the future-looking management of Flowgate capacity in accordance with a reciprocal agreement as defined in this document.

Security Constrained Dispatch - Security Constrained Dispatch is the utilization of the least cost economic dispatch of generating and demand resources while recognizing and solving transmission constraints over a single Operating Entity Market.

Appendix B - NERC Policy Impacts

The MISO/PJM Policy Review Task Force is working with the MISO and PJM to identify what Policy changes may be necessary to enable the expansion of the LMP market over the PJM Operating Entity footprint. Appendix B will be modified as necessary to address other impacts that may be noted by the Task Force as their work progresses. The Policy Review Task Force is responsible for coordinating its work with the applicable NERC Subcommittees so that Policy changes can be developed and provided to the NERC Standing Committees for approval.

Appendix C - E-Tag and IDC Impacts

Overview

Much of the following was developed with the assistance of Open Access Technology, International (OATI) and the NERC IDC Working Group.

Proposed Changes

E-Tag Changes

To ensure that the IDC has enhanced granularity for transactions tagged in or out of a large market, MISO and PJM recommend that the IDC be reconfigured to accept the market's marginal units. By providing both the real-time and projected marginal units the IDC will be better able to model where generation is actually moving to support schedule changes. This recommended improvement differs significantly from the current IDC modeling of PJM transactions, because the calculations will not be using a static single point within the PJM system. The actual process for providing these units consists of the following:

a. MISO and PJM will determine these marginal units based upon the look-ahead solutions in their respective Unit Dispatch Systems the locations on the system where generation is expected to be marginal, and upload this information to the IDC.
b. MISO and PJM will indicate where the generation would move depending on the MW amount of curtailments that are necessary. There will be one or more sets of participation factors to represent exports from each market area and one or more sets of participation factors to represent imports into each market area..
c. This information would be transmitted in the form of adjustments to the generation participation factors that are already present in the IDC.
d. The IDC could then utilize this information in the calculation of Control Area to Control Area distribution factors instead of the current methodology of utilizing a static model of all generators within a Control Area's boundaries.
e. These locations could be as granular as individually identified generators. Note though, for market confidentiality reasons Operating Entity will mask the actual generator
f. PJM and MISO each simultaneously optimize and dispatch for all constraints currently confronting the system operators. Upon implementation of the inter-regional congestion coordination scheme, the Operating Entity would add to the current simultaneous constraint evaluation any Flowgate for which the inter-regional congestion

coordination had been initiated. Therefore, the marginal units the Operating Entity would transmit to the IDC for next hour curtailment evaluation would include the simultaneous evaluation of the Flowgate for which curtailments would be requested. The IDC would in fact have all information necessary to accurately determine transaction distribution factors on the constrained facilities.

PJM and MISO propose that they will each supply to the IDC one or more sets of marginal source generators to be used to model all interchange transactions out of their respective markets for all Flowgates. PJM and MISO propose that they will each supply the IDC one or more sets of marginal sink generators to be used to model all interchange transaction into their respective markets for all Flowgates. These sets will be periodically updated by the Operating Entity through a new e-tag message. In addition, each Market Area will be partitioned into zones, and the Operating Entities will send the IDC marginal zone participation factors for more frequent updates. The Operating Entities will provide the IDC with different zonal participation factors for import and export. Depending on the market area configuration, topology, network impedance, geographical location, generation locations, one or more sets of marginal units may be appropriate to represent sinks in the IDC. The IDC should compute different TDFs for tags that source (export) and sink (import) into the market areas, based on the import and export participation factors.

- In order to overcome bandwidth restrictions, the IDC vendor (OATI) suggests PJM to partition its network into zones that can be modeled in the IDC. The number of zones should be small compared to the number of generators. PJM may have at least 12 to as many as 24 different zones. MISO will have at least 30 zones.

- Every hour, the Operating Entities would provide the IDC with the generator participation factors within each zone. The participation factors would be the same for all Flowgates. IDC would calculate TDFs for every source/sink (and zone) for every Flowgate.

- The IDC would publish TDFs for current and next hour for every zone.

- At every LMP cycle, the Operating Entities would provide the IDC with the zone weighting factors that are the same for all Flowgates. Different zone weighting factors can be submitted for import (tags sinking in the market area) and export (tags sourcing in the market area).

- At the time of a TLR the IDC would dynamically compute a market area footprint TDF for import and export based on the most recently received zonal weighting factors, and use the footprint TDF for every tag that sources or sinks in the market area. This can be calculates by:

$TDF_{MA\text{-}Import} = \sum z\ W_{z\text{-}Import} \times TDF_z / \sum_z W_{z\text{-}Import}$
$TDF_{MA\text{-}Export} = \sum z\ W_{z\text{-}Export} \times TDF_z / \sum_z W_{z\text{-}Export}$

Where:
- o $TDF_{MA\text{-}Import}$ is the Market Area footprint TDF for importing transactions
- o $TDF_{MA\text{-}Export}$ is the Market Area footprint TDF for exporting transactions
- o $W_{z\text{-}Import}$ is the Market Area zone z weighting factor for importing transactions
- o $W_{z\text{-}Export}$ is the Market Area zone z weighting factor for exporting transactions
- o TDF_z is the market Area zone z TDF

• The IDC currently archives the TDFs on a Flowgate in TLR. The IDC would also archive the generator participation factors within the each market area zone and the zonal participation factors at the time the TLR is requested. This would provide the IDC users with the ability to audit the IDC results. The IDC could also update the market area footprint TDF every time the IDC receives new zonal weighting factors from the Operating Entity, which can be used by NERC for presentation through the NERC TDF viewer.

This approach provides the market with knowledge of TDFs, enables the IDC to publish much fewer values to the NERC sites – hourly (current and next hour) TDFs for the market area zones and other Control Areas and updates of the market area footprint TDF throughout the hour. It also reduces the traffic between the IDC and the Market Base Operating Entities, thus minimizing the communication infrastructure enhancement requirements.

Tagged transactions that source or sink in the market area would impact a Flowgate based on the PJM footprint TDF on the Flowgate, which is update throughout the hour based on zonal weighting factors. Transactions wheeled through the market area would only depend on the transactions source and sink TDFs.

IDC Changes

The requirement of this change order was developed to ensure the reliability of the bulk electric system is always maintained, and to ensure the NERC IDC is capable of determining accurate flow gate reductions representative of the entities actually creating the flows on the system. The expanded market footprints include additional Control Areas being incorporated into the existing PJM LMP market and MISO starting its LMP market, and involves the termination of using transmission reservations and NERC tags to represent system flows for those Control Areas internal to each market. The NERC IDC must be capable of receiving flow gate impacts created by each of the LMP markets.

Transactions going in and / or out, and through the PJM territory will continue to be tagged. Source / Sink bus points need to be determined in order to eliminate any type of gaming. During TLR, these tagged transactions will be curtailed as prescribed by the IDC, and could involve any of the current transmission priority buckets. The level of granularity and what E-tagging fields are used by the IDC to assign TDF factors to these transactions will be addressed in the near future.

In order to accomplish these changes necessary to incorporate the LMP markets into the IDC there will be NERC Policy, IDC software, algorithm, and database changes needed.

PROPOSED CHANGE DESCRIPTION:

IDC File Import Requirements:
The LMP market impact files will be sent to the IDC or specified location at least every fifteen minutes. These files will include market impact information for two transmission priorities or categories, for every flow gate identified by the LMP Market agreement. This may not include all Flowgates in the NERC BoF. IDC TDF calculations will continue to be done for the LMP market regions on all Flowgates to ensure that all tagged transactions from / into the market are curtailed properly during the TLR process.

The three transmission priorities that will be included in the LMP market impact file are:

1. Priority 2-NH (non-firm hourly Economic Impacts of LMP Market)
2. Priority 6-NN (Economic Impacts of LMP Market)
3. Priority 7-F (Firm NNL Impacts)

The LMP engine will transfer two types of files to the IDC or specified location. A Current hour file will be sent at least every fifteen minutes, and one next hour file will be sent at (and no later than) 25-minutes after the hour.
Each file will contain flow impact information for priority 2-NH, 6-NN, and 7-F for each identified flow gate. The LMP engine information associated with the flow gate calculations will be posted on the market OASIS for review.

The file transferred to the IDC will be in XML format. The field specifications will be identified when development begins.

If there is an error with the gathering/uploading or content of the LMP market impact file the values from the last good file will be used until a correct file can be retrieved. There should be an error sent to the RC to alert them of the file error.

LMP Flow Gate Impact Calculation Protocol:

Flow gate impact protocol "proposals" are identified in the PJM / MISO Congestion Management White paper. The flow gate protocol process will be added to this NERC IDC change order once a defined process has been approved.
IDC Weighting Factor Algorithm Change Requirements:
Since the LMP markets will be sending the flow impact for specified Flowgates there will be no calculated TDF for that impact for use during the curtailment process. The weighting factor algorithm that is used to calculate the curtailments for priorities 2-NH, 6-NN and 7-FIRM will need to be changed.

The curtailment and reallocation of the priority 2-NH and 6-NN buckets will need to be modified to be like the curtailment in the priority 7-FIRM bucket to allow the flow impact information to be used to assign curtailment amounts on a pro-rata basis (based on the MW level of the MW total to all such Interchange Transactions). Consequently all transactions using 2-NH and 6-NN Transmission Service will be put in the same sub-priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance. This change will also require a NERC Appendix 9C1 change in language.

The curtailment and reallocation of the priority 7-FIRM bucket will be the same with the exception that NO NNL Responsibility should be calculated for any of the CAs that are in the LMP market. The flow impact that will be sent to the IDC will already include the NNL portion for each area and there would be double counting if the 7-FIRM process also assigned NNL responsibility.

Note that the IDC will remain responsible for calculating RTO NNL Impacts for any Flowgate that is NOT reported by the RTO. For example, if a "Flowgate on the fly" is defined and the RTO has not reported data for that Flowgate, until such time as the RTO does begin reporting such data, the IDC will use its current methods to determine the RTO's impacts on that flowgate.

IDC Curtailment Report Change Requirements:

Non-firm schedule curtailments including transmission priority 1-NS through priority 5-NM will be prescribed for curtailment by the IDC as it is currently done.

Non-firm schedule curtailments of transmission priority 2-NH and 6-NN will include schedules identified by bucket 2-NH and 6-NN NERC tags, and by LMP market economic impacts. For non-firm priority 2-NH and 6-NN curtailments, the IDC curtailment report will prescribe a megawatt reduction requirement for the particular flow gate in TLR for each level as appropriate. The Reliability Coordinator associated with the LMP market having a reduction responsibility will initiate a re-dispatch order representative of the IDC LMP flow gate reduction order, as well as curtail NERC tags sinking into the LMP market. The status of the LMP economic impact will be "Re-Dispatch" until there is no longer a curtailment in the Priority 6-NN bucket where the status will return to "Proceed". The LMP market economic impact should never reach the "HOLD" status, as there will always be a value in the IDC for use (i.e. if there is a problems gathering the information the previous impact should be used).

Firm schedule curtailments of transmission priority #7 will include schedules identified by bucket #7 NERC tags, by Control Area NNL reductions, and by LMP market firm. The firm LMP market impact value used by the IDC will include firm schedules and NNL impacts created by the market as one number. For firm priority #7 curtailments, the IDC firm curtailment report will prescribe a megawatt reduction requirement for the particular flow gate in TLR. The Reliability Coordinator associated with the LMP market having a reduction responsibility will initiate a re-dispatch order representative of the IDC LMP flow gate reduction order, as well as curtail NERC tags sinking into the LMP market. The status of the LMP FIRM impact will be "Re-Dispatch" until there is no longer a curtailment in the Priority 7-FIRM bucket where the status will return to "Proceed". The LMP market Firm impact should never reach the "HOLD" status, as there will always be a value in the IDC for use (i.e. if there is a problems gathering the information the previous impact should be used).

IDC Screen Change Requirements:

Various IDC screen options will be modified in order to display LMP market impacts. For example, when selecting the "whole transaction" list option for a particular flow gate, the IDC will display the LMP priority #6 and #7 accordingly. Some examples are included below.

NERC IDC Display Information:

The following pages represent NERC IDC screen displays. The displays provide information with respect to how the IDC works today, and how the tool will work with the proposed LMP market change order. The Eau Claire – Arpin flow gate was used in the examples. The displays provide information for:

1) IDC "Whole Transaction list" for Eau Claire – Arpin as the tool is today.
2) IDC "Whole Transaction list" for Eau Claire – Arpin with the proposed LMP market change order.
3) TLR level 3B "Eau Claire – Arpin" Curtailment Report (50MWs of relief), as the tool works today, and with the proposed LMP market change order.
4) TLR level 3B "Eau Claire – Arpin" Curtailment Report (155MWs of relief), as the tool works today.
5) TLR level 3B "Eau Claire – Arpin" Curtailment Report (155MWs of relief), with the proposed LMP market change order.
6) TLR level 3B "Eau Claire – Arpin" Curtailment Report (100MWs of relief), with the proposed LMP market change order

Eau Claire – Arpin Flow Gate Information:

The following IDC screen shot represents a NERC IDC "whole transaction" list as it works today.

Sink SC	Method	Tag Name	Reservation MW	Reservation Priority	Reliability Cap	Market Cap	Actual MW	Amount on Flowgate Schedule	Amount on Flowgate Active	TDF (%)
EES	WL	MEC_TNSKDLJAN0278_EES	150	1-NS	150	150	150	11.0	11.0	7.1
MISO	WL	OTP_OTPW010007985_MPS	20	1-NS	20	20	20	2.4	2.4	12.2
PJM	CPM	NSP_NSPPCW0092573_PJM	280	1-NS	280	280	280	55.2	55.2	19.7
		Total for 1-NS	**450**		**450**	**450**	**450**	**68.6**	**68.6**	
EES	WL	SECI_CRGL1ASH0107P_EES	25	2-NH	25	25	25	1.4	1.4	5.6
MAIN	WL	MEC_AME010054962_PJM	150	2-NH	150	150	150	11.0	11.0	7.3
MISO	CPM	NSP_NSPPCW0092737_OPPD	6	2-NH	6	6	6	0.8	0.8	13.3
MISO	WL	WAUE_REMC010002263_MPS	250	2-NH	250	250	250	24.0	24.0	9.3
TVA	WL	MEC_APMM1JAN3024_AECI	50	2-NH	50	50	50	3.0	3.0	6.0
TVA	CPM	NSP_NSPPCW0092750_AECI	350	2-NH	350	350	350	69.0	69.0	19.7
		Total for 2-NH	**831**		**831**	**831**	**831**	**109.2**	**109.2**	
PJM	WL	KCPL_CNCTET0005785_PJM	53	3-ND	53	53	53	3.1	3.1	5.8
TVA	WL	NPPD_TEA01TEO3010_AECI	60	3-ND	60	60	60	4.3	4.3	7.2
		Total for 3-ND	**113**		**113**	**113**	**113**	**7.4**	**7.4**	
MISO	CPM	ALTW_ALTMA10008672_ALTE	79	6-NN	79	79	79	12.2	12.2	15.4
MISO	CPM	CE_ALTMA10008643_ALTE	200	6-NN	200	200	200	12.8	12.8	6.4
MISO	CPM	CE_ALTMA10008651_ALTE	150	6-NN	150	150	150	9.6	9.6	6.4
MISO	CPM	OTP_WEPM24000813J_WEC	200	6-NN	200	200	200	51.2	51.2	25.6
MISO	CPM	WAUE_REMC010002261_WEC	300	6-NN	300	300	300	68.1	68.1	22.7
TVA	WL	MEC_APMM1JAN2912_AECI	8	6-NN	8	8	8	0.5	0.5	6.0
		Total for 6-NN	**737**		**737**	**737**	**737**	**86.4**	**86.4**	
MAIN	WL	MEC_CPS010101F00_AMRN	30	7-F	30	30	30	2.2	2.2	7.3
MAIN	WL	MEC_MECBULET01105_CE	360	7-F	360	360	360	38.2	38.2	10.6
MAIN	WL	MEC_MECBULET01106_AMRN	11	7-F	11	11	11	0.8	0.8	7.3
MISO	CPM	ALTE_WPPI010040617_WPS	10	7-F	10	10	10	1.0	1.0	9.6
MISO	CPM	ALTW_ALTMA10008479_ALTE	154	7-F	79	79	79	12.2	12.2	15.4
MISO	CPM	ALTW_ALTMA10008656_ALTE	50	7-F	50	50	50	7.7	7.7	15.4
MISO	WL	WAUE_UGPM010003879_MEC	300	7-F	300	300	300	17.1	17.1	5.7
MISO	WL	WAUE_UGPM010003880_MEC	200	7-F	200	200	200	11.4	11.4	5.7
MISO	CPM	WEC_CWPC010004010_WPS	4	7-F	4	4	4	0.4	0.4	9.6
MISO	CPM	WEC_WPSM010001684_UPPC	65	7-F	65	65	65	3.8	3.8	5.9
TVA	WL	LES_APMM1JAN2910_AECI	40	7-F	40	40	40	2.6	2.6	6.6
TVA	WL	MEC_AECIJAN1011_AECI	4	7-F	4	4	4	0.2	0.2	6.0
TVA	WL	MEC_APMM1JAN2911_AECI	250	7-F	250	250	250	15.0	15.0	6.0
TVA	WL	MEC_MECBULET01003_AECI	150	7-F	150	150	150	9.0	9.0	6.0
		Total for 7-F	**1628**		**1628**	**1628**	**1628**	**63.5**	**63.5**	
		Global Total	**3759**		**3759**	**3759**	**3759**	**335.1**	**335.1**	

<u>Eau Claire – Arpin Flow Gate Information:</u>

The following IDC screen shot represents a NERC IDC "whole transaction" list with the proposed LMP market change order.

Sink SC	Method	Tag Name	Reservation MW	Reservation Priority	Reliability Cap	Market Cap	Actual MW	Amount on Flowgate Schedule	Amount on Flowgate Active	TDF (%)
EES	CPM	NewCo_TNSKDLJAN0278_EES	50	1-NS	50	50	50	3.6	3.6	7.1
PJM	CPM	NewCo_NSPPOW0092573_PJM	168	1-NS	168	168	168	33.0	33.0	19.7
		Total for 1-NS	**238**		**238**	**238**	**238**	**36.9**	**36.9**	
EES	WL	SECI_CRGL1ASH0107P_EES	25	2-NH	25	25	25	1.4	1.4	5.6
PJM	CPM	NewCo_AME010054962_PJM	50	2-NH	50	50	50	3.6	3.6	7.3
EES	CPM	NewCo_APMM1JAN3024_EES	50	2-NH	50	50	50	3.0	3.0	6.0
FPL	CPM	NewCo_NSPPOW0092750_FPL	105	2-NH	105	105	105	20.6	20.6	19.7
		Total for 2-NH	**230**		**230**	**230**	**230**	**28.6**	**28.6**	
PJM	CPM	NewCo_CNCTET0005785_PJM	53	3-ND	53	53	53	3.1	3.1	5.8
TVA	WL	SPC_TEA01TEO3010_AECI	60	3-ND	60	60	60	4.3	4.3	7.2
		Total for 3-ND	**113**		**113**	**113**	**113**	**7.4**	**7.4**	
MISO	CPM	NewCo LMP Market Economic Disp.		6-NN					79.3	
PJM	WL	PJM LMP Market Economic Disp.		6-NN					15.0	
EES	CPM	NewCo_APMM1JAN2912_EES	8	6-NN	8	8	8	0.5	0.5	6.0
		Total for 6-NN	**8**		**8**	**8**	**8**	**94.8**	**94.8**	
PJM	CPM	NewCo_CPS010101F00_PJM	30	7-F	30	30	30	2.2	2.2	7.3
PJM	CPM	NewCo_MECBULET01105_PJM	160	7-F	160	160	160	16.9	16.9	10.6
MISO	CPM	NewCo LMP Market NNL		7-F					120.0	
PJM	WL	PJM LMP Market NNL		7-F					16.0	
TVA	CPM	NewCo_APMM1JAN2910_AECI	40	7-F	40	40	40	2.6	2.6	6.6
TVA	CPM	NewCo_AECIJAN1011_AECI	4	7-F	4	4	4	0.2	0.2	6.0
TVA	CPM	NewCo_APMM1JAN2911_AECI	142	7-F	142	142	142	8.5	8.5	6.0
TVA	CPM	NewCo_MECBULET01003_AECI	17	7-F	17	17	17	1.0	1.0	6.0
		Total for 7-F	**993**		**993**	**993**	**993**	**167.4**	**167.4**	
		Global Total	**2461**		**2461**	**2461**	**2461**	**335.1**	**335.1**	

<u>Eau Claire – Arpin Flow Gate Information:</u>

<u>50MW of relief was required in this example. Only up to priority #3 was impacted.</u>

SC Requestor: MISO **CA Requestor:** ALTE **TLR level:** 3B
Requested Relief: 50
IDC MW Curtailed: 432 **Trans. Curt.** 8 **Relief:** 50

Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW Cap	Status	Relief Provided
EES	MEC_TNSKDLJAN0278_EES	WL	1-NS	50	50	50	0	CURTAIL	3.6
TVA	NSP_NSPPOW0092573_AECI	CPM	1-NS	168	168	168	0	CURTAIL	33.0
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
MAIN	MEC_AME010054962_AMRN	WL	2-NH	50	50	50	0	CURTAIL	3.6
SWPP	OPPD_CRGL1ABJ0108J_EDE	WL	2-NH	50	50	50	0	CURTAIL	2.8
TVA	MEC_SEINC0000500_AECI	WL	2-NH	50	50	50	0	CURTAIL	3.0
PJM	KCPL_CNCTET0005785_PJM	WL	3-ND	53	53	16	37	CURTAIL	0.9
TVA	NPPD_TEA01TEO3010_AECI	WL	3-ND	60	60	23	37	CURTAIL	1.7
									50.0
			Total Curtailment:	506	506	432	74		

******NOTE:** The curtailment report above (when only including transmission curtailment priorities of bucket 0 – 5) will not change with the NERC IDC LMP market change order proposal.

Eau Claire – Arpin Flow Gate Information:

155MW of relief was required in the following example. Up to (and including) priority #6 was impacted.

The following IDC screen shot represents a NERC IDC "curtailment" list as it works today.

	SC Requestor:	MISO	CA Requestor:	ALTE		TLR level:	3B		
	Requested Relief:	155							
	IDC MW Curtailed:	1208	Trans. Curt.	24		Relief:	155		
Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW Cap	Status	Relief Provided
EES	MEC_TNSKDLJAN0278_EES	WL	1-NS	50	50	50	0	CURTAIL	3.6
TVA	NSP_NSPPOW0092573_AECI	CPM	1-NS	168	168	168	0	CURTAIL	33.1
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
MAIN	MEC_AME010054962_AMRN	WL	2-NH	50	50	50	0	CURTAIL	3.6
TVA	MEC_SEINC0000500_AECI	WL	2-NH	50	50	50	0	CURTAIL	3.0
PJM	KCPL_CNCTET0005785_PJM	WL	3-ND	53	53	53	0	CURTAIL	3.1
TVA	NPPD_TEA01TEO3010_AECI	WL	3-ND	60	60	60	0	CURTAIL	4.1
MISO	ALTW_ALTMA10008672_ALTE	CPM	6-NN	78	78	78	0	CURTAIL	12.0
MISO	CE_ALTMA10008643_ALTE	CPM	6-NN	100	100	67	33	CURTAIL	4.3
MISO	CE_ALTMA10008651_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_ALTMA10008652_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_ALTMA10008653_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_ALTMA10008654_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_MSCG01MS39921_ALTE	CPM	6-NN	25	25	17	8	CURTAIL	1.1
MISO	CE_MSCG01MS39922_WEC	CPM	6-NN	25	25	17	8	CURTAIL	1.1
MISO	CE_WEPM24000813Q_WEC	CPM	6-NN	100	100	68	32	CURTAIL	4.4
MISO	MHEB_CRGL1AAA0107C_WEC	CPM	6-NN	100	100	100	0	CURTAIL	29.9
MISO	MPW_WEPM24000813X_WEC	CPM	6-NN	50	50	48	2	CURTAIL	5.5
MISO	MP_OTPW010007958_OTP	CPM	6-NN	50	50	29	21	CURTAIL	1.5
MISO	MP_OTPW010007975_OTP	CPM	6-NN	30	30	17	13	CURTAIL	0.9
MISO	NSP_WEPM24000813O_WEC	CPM	6-NN	100	100	50	0	CURTAIL	14.2
MISO	OTP_WEPM24000813J_WEC	CPM	6-NN	100	100	60	0	CURTAIL	12.7
MISO	WAUE_REMC010002261_WEC	CPM	6-NN	100	100	60	0	CURTAIL	13.2
TVA	MEC_APMM1JAN2912_AECI	WL	6-NN	8	8	5	3	CURTAIL	0.3
									156.
			Total Curtailment:	1522	1522	1208	184		

<u>Eau Claire – Arpin Flow Gate Information:</u>

<u>155MW of relief was required in this example. Up to (and including) priority #6 was impacted.</u>

The following IDC screen shot represents a NERC IDC "curtailment" list with the proposed LMP market change order.

	SC Requestor:	MISO	CA Requestor:	ALTE		TLR level:	3B		
	Requested Relief:	155							
	IDC MW Curtailed:	1338	Trans. Curt.	10		Relief:	155		

Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW Cap	Status	Relief Provided
EES	NewCo_TNSKDLJAN0278_EES	CPM	1-NS	50	50	50	0	CURTAIL	3.6
PJM	NewCo_NSPPOW0092573_PJM	CPM	1-NS	168	168	168	0	CURTAIL	33.1
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
PJM	NewCo_AME010054962_PJM	CPM	2-NH	50	50	50	0	CURTAIL	3.6
EES	NewCo_APMM1JAN3024_EES	CPM	2-NH	50	50	50	0	CURTAIL	3.0
FPL	NewCo_NSPPOW0092750_FPL	CPM	2-NH	105	105	105	0	CURTAIL	3.0
PJM	NewCo_CNCTET0005785_PJM	CPM	3-ND	53	53	53	0	CURTAIL	3.1
TVA	SPC_TEA01TEO3010_AECI	WL	3-ND	60	60	60	0	CURTAIL	4.1
MISO	NewCo LMP Market Economic Disp.	CPM	6-NN		80		0	Re-Dispatch	80.0
PJM	PJM LMP Market Economic Disp.	WL	6-NN		15		0	Re-Dispatch	15.0
EES	NewCo_APMM1JAN2912_EES	CPM	6-NN	50	50	50	0	CURTAIL	6.0
									156.0
			Total Curtailment:	611	706	1338			

FIRM CURTAILMENTS:
****NOTE: The curtailment report above represents the identical process used when curtailing firm (transmission priority #7). The exception of the above, is that a firm curtailment report will include and display the Control Areas located outside the LMP market that have an NNL reduction responsibility.

<u>Eau Claire – Arpin Flow Gate Information:</u>

<u>100MW of relief was required in this example. Up to priority #6 was impacted.</u>

The following IDC screen shot represents a NERC IDC "curtailment" list with the proposed LMP market change order.

SC Requestor: MISO	**CA Requestor:** ALTE	**TLR level:** 3B	
Requested Relief: 100			
IDC MW Curtailed: 1338	**Trans. Curt.** 10	**Relief:** 100	

Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW / FG-Impact Cap	Status	Relief Provided
EES	NewCo_TNSKDLJAN0278_EES	CPM	1-NS	50	50	50	0	CURTAIL	3.6
PJM	NewCo_NSPPOW0092573_PJM	CPM	1-NS	168	168	168	0	CURTAIL	33.1
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
PJM	NewCo_AME010054962_PJM	CPM	2-NH	50	50	50	0	CURTAIL	3.6
EES	NewCo_APMM1JAN3024_EES	CPM	2-NH	50	50	50	0	CURTAIL	3.0
FPL	NewCo_NSPPOW0092750_FPL	CPM	2-NH	105	105	105	0	CURTAIL	3.0
PJM	NewCo_CNCTET0005785_PJM	CPM	3-ND	53	53	53	0	CURTAIL	3.1
TVA	SPC_TEA01TEO3010_AECI	WL	3-ND	60	60	60	0	CURTAIL	4.1
MISO	NewCo LMP Market Economic Disp.	CPM	6-NN		80		45	Re-Dispatch	35.0
PJM	PJM LMP Market Economic Disp.	WL	6-NN		15		8	Re-Dispatch	7.0
EES	NewCo_APMM1JAN2912_EES	CPM	6-NN	50	50	50	25	CURTAIL	3.0
			Total Curtailment:	611	706	1338			100.0

FIRM CURTAILMENTS:
****NOTE: The curtailment report above represents the identical process used when curtailing firm (transmission priority #7). The exception of the above, is that a firm curtailment report will include and display the Control Areas located outside the LMP market that have an NNL reduction responsibility

Appendix D- Implementation Schedule

Feb 2003-Mar 2004

- PJM & MISO continues to refine their respective models to include all Coordinated Flowgates
- PJM & MISO build processes to execute Whitepaper initiatives
- PJM & MISO implement Hold Harmless Rulings, as required

March - April 2004

- NERC Training Materials Distributed
- MISO and PJM conduct training, tests, and drills of the congestion management solutions
- MISO tests NNL calculations, PJM validates
- OATI Testing with MISO/PJM

May 2004

- PJM implements market expansion through ComEd
- PJM Congestion Management Solutions are implemented
- PJM/MISO Phase 1 of the JOA is implemented
- PJM/MISO improve processes when areas for improvement are identified (i.e., list of Coordinated Flowgates may grow)

Oct 2004

- PJM implements market expansion through AEP and DPL

Nov 2004

- PJM implements market expansion through Dominion VAP

Dec 2004

- MISO implements market throughout the MISO footprint
- PJM/MISO Phase 2 of the JOA is implemented

2005 and beyond

- As PJM's and MISO's markets grow – additional versions of the Reliability Plan will require approval and list of Coordinated Flowgates will change
- MISO and PJM improve processes for Market to Market Operations

Appendix E - PJM/MISO Examples and Case Studies

Summary

For these two examples the Historical and Two Days Prior Allocation was simulated for two Coordinated FGs. Third Party impacts were included along with current CBM and TRM values. The results were as follows:

FGs Studied:
6081 Quad Cities West
3241 Zion-Pleasant Prairie flo Wempletown-Paddock

Historical Allocation

FG #	MISO	PJM
6081	392	597
3241	873	288

Historical NNL %

FG #	MISO	PJM
6081	39.6%	61.4%
3241	75.4%	24.6%

Two Day Out Allocation

FG #	MISO	PJM
6081	448	681
3241	873	288

The rest of the write up will step through the examples and the Allocation process.

Step #1: Historical Allocation

Assume PJM consists of PJM Classic and CE only
Assume MISO Market consists of 30 "Day One" CAs

NNL will be calculated as each CA to its OWN load down to 0% in the From – To Direction.

Model : Current IDC Summer Base Case – no SDX Data. The appropriate MMWG case will be used for the actual Allocation that takes place.

Change Net Interchange such that it is zero for all participants (for both net export and import CAs per the process). The scaling will be done based on the MBASE of each unit in a CA

FG # 6081

TTC = 1400
TRM = 216
CBM = 0

FG Limit = TTC –TRM-CBM = 1184

NNL:

	MISO	PJM
>5%	89.9	219.5
<5%	114.65	16.35

FIRM Reservations:

	MISO	PJM
>5%	77.95	278.75
<5%	62.1	10

NNL +FIRM:

	MISO Final	PJM Final	Other Entities
>5%	167.85	498.25	195
<5%	176.75	26.35	N/A

The first step in the Allocation is to sum the >5% impacts for the FG. When this was done the FG came in allocated at 861.1 MW. This leaves additional room on the FG for 312.9MW before hitting the FG Limit of 1184MW.

The next step in the Allocation process is to start to allow the <5% impacts to be allocated up to the point of the FG Limit. In this case there is room for all <5% impacts to be added for each entity before the FG Limit is reached. With the addition of the <5% impacts the total Allocation on the FG becomes 1064.2. This indicates that there is room for additional Allocation of 119.8MW for PJM and MISO on the FG.

These remaining MW are allocated by using a pro-rata approach between the two reciprocating entities using the ratio of the Historical NNL values.

MISO Historical NNL= (MISO Historical >5% +MISO Historical <5%) =344.6 MW
PJM Historical NNL=(PJM Historical >5% +PJM Historical <5%)= 524.6 MW

MISO Historical Allocation % = 39.6%
PJM Historical Allocation %= 61.4%

MISO's additional FG Allocation = 47.4 MW
PJM's additional FG Allocation = 72.3 MW

Total Historical Allocation for FG 6081

MISO	PJM	Other Entities
392	597	195

FG # 3421

Limit = 1195
TRM = 24
CBM = 0

FG Limit = TTC –TRM-CBM = 1171

NNL:

	MISO	PJM
>5%	117.6	0
<5%	107.38	12

FIRM Reservations:

	MISO	PJM
>5%	580.65	263.9
<5%	81.2	14

NNL +FIRM:

	MISO	PJM	Other Entities
>5%	698.25	263.9	10
<5%	188.55	26	N/A

The first step in the Allocation is to sum the >5% impacts for the FG. When this was done the FG came in allocated at 972.15 MW. This leaves additional room on the FG for 199 MW before hitting the FG Limit of 1171 MW.

The next step in the Allocation process is to start to allow the <5% impacts to be allocated up to the point of the FG Limit. In this case there is not room for all <5% impacts to be added for each entity before the FG Limit is reached.

These remaining <5% MW are allocated by using a pro-rata approach between the two reciprocating entities using the ratio of the <5% NNL values.

MISO <5% NNL= 188.5 MW
PJM <5% NNL = 26 MW

MISO <5% Allocation % = 87.9%
PJM <5% Allocation %= 12.1%

MISO's additional FG Allocation = 174.9 MW
PJM's additional FG Allocation = 24.1 MW

Total Historical Allocation for FG 3241

MISO	PJM	Other Entities
873	288	10

Historical Allocation

FG #	MISO	PJM
6081	392	597
3241	873	288

The reciprocal entity Historic NNL percentages are also recorded as these will be used in any subsequent Allocation for determining the amount of additional MWs to be assigned to each entity in the case there is room on the FG.

Historical NNL %

FG #	MISO	PJM
6081	39.6%	61.4%
3241	75.4%	24.6%

Step #2- Two Days Prior

The Reservation Piece was updated to include more up-to-date data. The updated reservations were estimated by grabbing an IDC Snapshot of all FIRM Tags that affect the FG by more than 0.1%.

The same Base Model as Historical Calculation was used with updated load forecast and topology from the SDX data for the study date. GLDF values were recalculated.

FG # 6081

TTC = 1400
TRM = 216
CBM = 0

FG Limit = TTC –TRM-CBM = 1184

NNL:

	MISO	PJM
>5%	189.41	242.01
<5%	55.44	13.83

FIRM Reservations:

	MISO	PJM
>5%	106.19	410.31
<5%	95.12	11.71

	MISO	PJM	Other Entities
>5%	295.60	652.32	55
<5%	150.56	25.54	0

The first step in the Allocation is to sum the >5% impacts for the FG. When this was done the FG came in allocated at 1002.92 This leaves additional room on the FG for 181.1 before hitting the FG Limit of 1184MW.

The next step in the Allocation process is to start to allow the <5% impacts to be allocated up to the point of the FG Limit. In this case there is room for all <5% impacts to be added for each entity before the FG Limit is reached. With the addition of the <5% impacts the total Allocation on the FG becomes 1179 his indicates that there is room for additional Allocation of 5MW for PJM and MISO on the FG.

To ensure that any previous additional Allocation is respected the amount of the Historical Allocation is compared to each entities current Allocation estimation. If the Historical Allocation is More Than the estimated current Allocation each entity is automatically allowed the amount of the previous Allocation. Otherwise the new estimated values are used.

Two Days Prior Estimated Allocation:

MISO = 446.16
PJM = 677.86

Historical Allocation:

MISO = 392
PJM = 597

Since the Historical Allocation is Less than the estimated Two Days Prior Allocation the remaining 5 MWs are allocated by using a pro-rata approach between the two reciprocating entities using the ratio of the Historical NNL values that was calculated above during the Historical Allocation.

MISO Historical Allocation = 39.6%
PJM Historical Allocation = 61.4%

MISO's additional FG Allocation = 2 MW
PJM's additional FG Allocation = 3 MW

Total Two Days Prior Allocation for FG 6081

MISO	PJM	Other Entities
448.16	680.86	55

FG # 3421

Limit = 1195
TRM = 24
CBM = 0

FG Limit = TTC –TRM-CBM = 1171

NNL:

	MISO	PJM
>5%	179.28	0
<5%	157.91	17.03

FIRM Reservations:

	MISO	PJM
>5%	674.1	265.4
<5%	77.85	18.45

	MISO	PJM	Other Entities
>5%	853	265.4	60
<5%	235	35.48	N/A

Since >5% impacts combined is Greater than FG Limit of 1171 the estimated Allocation will not have the addition of any <5% impacts included.

Two Days Prior Estimated Allocation:

MISO = 853
PJM = 265.4

To ensure that any previous additional Allocation is respected the amount of the Historical Allocation is compared to each entities current Allocation estimation. If the Historical Allocation is More Than the estimated current Allocation each entity is automatically allowed the amount of the previous Allocation. Otherwise the new estimated values are used.

Historical Allocation Values:

MISO = 873
PJM = 288

Since the Historical Allocation is More Than the estimated Two Days Prior Allocation the Reciprocal Entity Allocations are kept at this Historical level and those values are moved into the real time realm.

Two Day Out Allocation

FG #	MISO	PJM	
6081		448	681
3241	873	288	

The reciprocal entity Historic NNL percentages are also recorded as these will be used in any subsequent real time Allocation for determining the amount of additional MWs to be assigned to each entity in the case there is room on the FG.

Historical NNL %

FG #	MISO	PJM
6081	39.6%	61.4%
3241	75.4%	24.6%

Appendix F- List of Coordinated Flowgates

This appendix lists Coordinated Flowgates for the PJM and MISO RTOs. **Note that these lists are dynamic in nature, and may change over time as Flowgates' relevance increases or decreases.** PJM and MISO will post the most current version of this list on their OASIS to ensure stakeholders have access to the most current list at all times.

"Reciprocal with <RTO>" indicates that the Flowgate is also part of a Reciprocal Coordination agreement between PJM and the Midwest ISO, and Flowgate Allocations will occur on this Flowgate on a future-looking basis. All flowgates marked with an "x" are the flowgates that both MISO and PJM will mutually respect.

"Owner" indicates what entity will be considered the entity from whom the AFC calculations will be considered when performing Allocations.

"Manager" indicates which entity will be responsible for performing the Allocations.

Note that some Midwest ISO Coordinated Flowgates are marked "TBD" for Owner and Manager. As Midwest ISO will not be implementing the Congestion Management portions of this document at this time, it is unnecessary to define Owners and Managers for non-Reciprocal Coordinated Flowgates.

PJM Coordinated Flowgates

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	2007	AEP	05COOK 765 05COOK 345 1	AEP	PJM
x	2008	AEP	05DUMONT 765 05DUMTEQ 999 1	AEP	PJM
x	2014	AEP, CE	05OLIVE 345 UPNOR;RP 345 1	AEP	PJM
x	2015	AEP, CE	05OLIVE 345 G ACR; T 345 1	AEP	PJM
x	2017	AEP	05COOK 345 05OLIVE 345	AEP	PJM
x	2032	CIN, AEP	08CAYSUB 345 05EUGENE 345	MISO	MISO
x	2213	NIPS, CE	State Line-Wolf Lake 138 flo Dumont 765/345 Tr	MISO	MISO
x	2214	NIPS, CE	State Line-Wolf Lake 138 flo UP North-Olive 345	MISO	MISO
x	2215	NIPS, CE	State Line-Wolf Lake 138 flo SLINE;5S-WASHI; R 138	MISO	MISO
x	2221	NIPS, CE	Munster-Burnham 345 flo Olive-University Park North 345	MISO	MISO
x	2223	NIPS, AEP	Dumont-Stillwell 345 flo Olive-Green Acre 345	MISO	MISO

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	2286	CE, NIPS	Burnham-Munster 345 flo Dumont-Wilton Center 765	MISO	MISO
x	2287	CE, NIPS	Burnham-Munster 345 flo Dumont-Wilton Center 765 + Op Guide	MISO	MISO
x	2288	CE, NIPS	Burnham-Sheffield 345 flo Dumont-Wilton Center 765	MISO	MISO
x	2296	CE, NIPS	Munster-Burnham 345 flo University Park North-E. Frankfort 345	MISO	MISO
x	2298	AEP, NIPS	New Carlisle-Trail Creek 138 flo University Park North-E. Frankfort 345	MISO	MISO
x	2299	AEP	Dumont-Stillwell 345 flo Dumont-Wilton Center 765	AEP	PJM
x	2400	AEP	DUMONT765-345TX-COOK765-345TX	AEP	PJM
x	2401	CE, AEP	DUMONT765/345TX-DUMONT WILTON C 765	AEP	PJM
x	2402	AEP	COOK765-345TX-DUMONT765-345TX	AEP	PJM
x	2497	NIPS	State Line-Wolf Lake 138	MISO	MISO
x	2890	CE, NIPS	State Line-Wolf Lake 138 flo E. Frankfort-University Park North 345	MISO	MISO
x	2913	NIPS, AEP	Stillwell-Dumont 345	MISO	MISO
x	3001	CE, ALTE	WEMPLETOWN-PADDOCK 345 KV	MISO	MISO
x	3003	ALTE	COLUMBIA-S. FOND DU LAC 345 KV	MISO	MISO
x	3006	ALTE,NSP,WEC,WPS	EAU CLAIRE-ARPIN 345 KV	MISO	MISO
x	3009	NSP,ALTE,WEC,WPS	EAU CLAIRE-ARPIN+WEMPLETOWN-PADDOCK	MISO	MISO
x	3011	ALTE	PADDOCK 345/138 XFMR 1	MISO	MISO
x	3012	ALTE	PADDOCK XFMR 1 + PADDOCK-ROCKDALE	MISO	MISO
x	3018	ALTE,WPS,WEC,NSP	EAU CLAIRE-ARPIN+PRAIRIE ISLAND-BYRON	MISO	MISO
x	3021	ALTE	Paddock-Blackhawk 138 (flo) Paddock-Townline 138	MISO	MISO
x	3024	ALTE	Blackhwk-Colley Road 138 (flo) Paddock-Townline 138	MISO	MISO
x	3025	ALTE	Russel-Rockdale 138/Paddock-Rockdale 345	MISO	MISO
x	3034	ALTE	Blackhawk-ColleyRd xfmr FLO Paddock-Rockdale345	MISO	MISO
x	3038	ALTE	Paddock-Townline 138 (flo) Paddock-Blackhawk 138	MISO	MISO
x	3045	ALTE	Rockdale 345/138 Xfmr 3 flo Paddock 345/138 Xfmr	MISO	MISO
x	3059	CE, ALTE	Wempletown-Paddock 345 flo Arpin-Rocky Run 345 + Op Guide	MISO	MISO
x	3060	CE, ALTE	Wempletown-Paddock 345 flo King-Eau Claire-Arpin 345 + Op Guide	MISO	MISO
x	3063	ALTE	Paddock-Townline 138 (flo) Paddock-Rockdale 345	MISO	MISO
x	3107	AMRN	MONTGOMERY-SPENCER 345 KV	MISO	MISO
x	3112	AMRN, CILC	DUCK CREEK-IPAVA 345 kV	MISO	MISO

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3114	AMRN, AEP	BREED-CASEY 345 KV	MISO	MISO
x	3115	AMRN	COFFEEN-PANA 345 KV	MISO	MISO
x	3120	AMRN	COFFEEN-PANA+MONTGMRY-SPENCER	MISO	MISO
x	3123	AMRN	COFFEEN-PANA+DUMONT-WILTON CENTER	MISO	MISO
x	3127	AMRN	TAYLORVILLE-PAWNEE + COFFEEN-PANA-KINCAID	MISO	MISO
x	3131	AMRN	PAWNE-AUBURN+KINCAID-LATHM	MISO	MISO
x	3139	AMRN	PAWNEE WEST XFMR + PANA-KINCAID	MISO	MISO
x	3140	AMRN	MONTGMRY-SPENCER+COFFEEN-PANA-KINCAID	MISO	MISO
x	3142	AMRN	RAMSEY-PANA + COFFEEN-PANA-KINCAID	MISO	MISO
x	3145	AMRN	PANA XFMR + COFFEEN-COFFEEN NORTH	MISO	MISO
x	3159	AMRN	Neoga-Holland-Ramsey 345 Bland-Franks 345	MISO	MISO
x	3161	AMRN, CWLP	Auburn-Chatham 138 flo Latham-Kincaid 345	MISO	MISO
x	3201	CE, AEP	11215 DUMONT-WILTON 765KV(AEP-CE)	PJM	PJM
x	3202	CE	17723 BURNHAM-TAYLOR 345KV	PJM	PJM
x	3203	CE	10802 LOCKPORT-LISLE 345 KV RED	PJM	PJM
x	3204	CE	10801 LOCKPORT-LISLE 345 KV BLUE	PJM	PJM
x	3205	CE	16703 PLANO- ELECT JCT 345 KV RED	PJM	PJM
x	3206	CE	16704 PLANO-ELECT JCT 345 KV BLUE	PJM	PJM
x	3207	CE	TSS116 GOODINGS GR 345KV RED BUSTIE	PJM	PJM
x	3208	CE	0621 BYRON-CHERRY VALLEY 345KV BLUE	PJM	PJM
x	3209	CE	622 BYRON-CHERRY VALLEY 345KV RED	PJM	PJM
x	3210	CE	10802 Lock-LisR for 10801Lock-LiB+G	PJM	PJM
x	3211	CE	10801 Lock-LisB for 10802Lock-LiR+G	PJM	PJM
x	3212	CE	10802 Lock-Lisl R for 16703 PL-EJ R	PJM	PJM
x	3213	CE	10801 Lock-Lisl B for 16704 PL-EJ B	PJM	PJM
x	3214	CE	10322 Lis-LomR for 10321 Lis-LomB+G	PJM	PJM
x	3215	CE	10321 Lis-LomB for 10322 Lis-LomR+G	PJM	PJM
x	3216	CE	0621 Byron-ChV B for 0622 Byr-ChV R	PJM	PJM
x	3217	CE	0621 Byron-ChV B for 0624 Byr-Wemp	PJM	PJM
x	3218	CE	0622 Byron-ChV R for 0621 Byr-ChV B	PJM	PJM

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3219	CE	0622 Byr-ChV Red for 0624 Byr-Wemp	PJM	PJM
x	3220	CE	16704 Plan-EJ B for 16703 Plan-EJ R	PJM	PJM
x	3221	CE	16703 Plan-EJ Red for 16704 Pl-EJ B	PJM	PJM
x	3222	CE	11601 EFrk-GoodiB for 11602 EF-GG R	PJM	PJM
x	3223	CE	11602 EFrk-GoodiR for 11601 EF-GG B	PJM	PJM
x	3227	CE	0404 Quad-H471 for 15503 Cordo-Nelson	PJM	PJM
x	3228	CE	0403 Quad-Cord-Nelson for 0404 Quad-H471	PJM	PJM
x	3229	CE	11604 Goodi-LockR for 11617GG-LockB	PJM	PJM
x	3230	CE	11617 Goodi-LockB for 11604GG-LockR	PJM	PJM
x	3231	CE	GOODI 345R BT for 1223Dres-EJ B+T83	PJM	PJM
x	3232	CE	11120 EJ-W407 for 10802 Lock-LiR +G	PJM	PJM
x	3233	CE	11124 EJ-Lomb for 10801 Lock-LiB +G	PJM	PJM
x	3234	CE	2102 Kincaid-Lath for 11215 Dum-Wlt	PJM	PJM
x	3235	CE	2101 Kinc-BrokTp for 11215 Dum-Wilt	PJM	PJM
x	3236	CE, ALTE	17101 Wemp-Pad for 9922 Zion-Arcad	MISO	MISO
x	3237	CE, ALTE	17101 Wemp-Pad for 2221 Zion-PlsPr	MISO	MISO
x	3238	CE, ALTE	17101 Wemp-Pad for 15616 ChV-Silver	MISO	MISO
x	3239	CE, ALTE	17101 Wemp-Pad for Arpin-ÉauClar +G	MISO	MISO
x	3240	CE, WEC	2221 Zion-PlsPr for 9922 Zion-Arcd	PJM	PJM
x	3241	CE, WEC	2221 Zion-PlsP for 17101 Wemp-Pad	PJM	PJM
x	3242	CE, WEC	9922 Zion-Arcad for 2221 Zion-PlsP	PJM	PJM
x	3244	CE	Nels Tr84 for 15502 Nels-EJ +Tr82	PJM	PJM
x	3245	CE	15616 Cher-Silv for 15502 Nels-EJ	PJM	PJM
	3246	CE	4525 Jef-KingsR for 10802Lock-Li R+G	PJM	PJM
	3247	CE	4527 Jef-KingsB for 10801 Lock-LiB+G	PJM	PJM
x	3248	CE	12204 Bel-Mar R for 15616 ChV-Silvr	PJM	PJM
x	3249	CE	12205 Bel-Mar B for 15616 ChV-Silvr	PJM	PJM
x	3250	CE	15502 Nels-EJ for 15616 Cher-Silv	PJM	PJM
x	3251	CE	0404 Quad Cities - NWS&W (H471)	PJM	PJM
x	3252	CE	11622 Elwd-GG R 345 for 1223 Dres-EJ R + Dres Tr 81	PJM	PJM

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3253	CE	Kewanee(CE)-Kewanee(IP) 138 BT	PJM	PJM
x	3254	CE	Pwr JctB-Powerton 138	PJM	PJM
x	3257	CE, MEC	Quad City-SUB 91 345 KV	PJM	PJM
x	3258	CE, ALTW, MEC	Quad City-Rock Creek (FLO) QC-SUB91	PJM	PJM
x	3259	CE, MEC	Quad-SUB 91 345 for MEC Cordova-SUB 39(Moline) 345kV	PJM	PJM
x	3260	CE	15501 Lee Co-Nelson 345 for 17101 Wemp-Pad 345	PJM	PJM
x	3261	CE	L8012 Pontiac-Wiltn345 for L8014 Pont-Dresd345	PJM	PJM
x	3262	CE	Nelson 345-138 T82 for Nelson 345-138 T84	PJM	PJM
x	3263	CE	Nelson-Dixon B FLO Nelson-Nelson RT	PJM	PJM
x	3264	CE	Nelson-Nelson RT FLO Nelson-Dixon B	PJM	PJM
x	3265	CE	OTDF ChV-Bel Red FLO ChV-SilvLk	PJM	PJM
x	3266	CE, ALTW	Garden Plain-Albany 138 flo Quad Cities-H471 345	PJM	PJM
x	3267	NIPS, CE	Munster-Burnham 345 flo Dumont-Wilton Center 765 + Op Guide	MISO	MISO
x	3268	NIPS, CE	Munster-Burnham 345 flo Dumont-Wilton Center 765	MISO	MISO
x	3269	NIPS, CE	Sheffield-Burnham 345 flo Dumont-Wilton Center 765	MISO	MISO
x	3270	CE, NIPS	State Line-Wolf Lake 138 flo Burnham-Sheffield 345	MISO	MISO
x	3271	CE, NIPS	State Line-Wolf Lake 138 flo Wilton Center-Dumont 765	MISO	MISO
x	3301	CILC	TAZEWELL - MASON 138 KV	MISO	MISO
x	3302	CILC	East Springfield-Holland 138 KV	MISO	MISO
x	3303	CILC, CWLP	E SPRINGFIELD-EASTDALE 138 KV	MISO	MISO
x	3304	CILC, CE	POWERTON-TAZEWELL 345 KV	MISO	MISO
x	3306	CILC	Holland-Mason138+Duck Creek-Tazewell345	MISO	MISO
x	3310	CE, CILC	Powerton-Tazewell 345 flo Powerton-Goodings Gr. 345 B	MISO	MISO
x	3311	CE, CILC	Powerton-Tazewell 345 flo Powerton-Goodings Gr. 345 R	MISO	MISO
x	3401	IP	SIDNEY XFMR + BUNSONVILLE XFMR	MISO	MISO
x	3405	IP, AEP	BUNSONVILLE-EUGENE + BREED-CASEY	MISO	MISO
x	3408	IP	PANA-MOWEAQ T + KINCAID-LATHAM	MISO	MISO
x	3410	IP	SIDNEY XFMR + DUMONT-WILTON	MISO	MISO
x	3413	AMRN, IP	COFFN-ROXFD IP FOR XENIA-MT VRNON	MISO	MISO
x	3414	AMRN, IP	COFFN-ROXFD IP FOR COFFN-COFFN N	MISO	MISO

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3416	IP	COFFEEN-ROXFORD 345	MISO	MISO
x	3418	IP	COFFEEN-ROXFORD 345 FOR LOSS OF BAKER-BROADFORD 765	MISO	MISO
x	3419	IP,AMRN	Xenia-MtVernon 345 for Coffeen-Roxfd 345	MISO	MISO
x	3420	IP	Coffeen-Roxford Rockport-Jefferson	MISO	MISO
x	3503	WEC	ALBERS-PARIS 138 KV	MISO	MISO
x	3507	ALTE,WEC	EDGEWATER-Cedarsauk-Granville 345 KV	MISO	MISO
x	3517	WEC	ARCADIAN-GRANVILE 345 KV	MISO	MISO
x	3527	WEC	PleasPr-Racine 345 for Wemp-Pad 345	MISO	MISO
x	3529	WEC,WPS	N. Appleton-Rocky Run 345kV	MISO	MISO
x	3534	WEC	Kenosha-Albers 138 for Wempletown-Paddock 345	MISO	MISO
x	3537	WEC	Kenosha-Lakeview 138 for PleasPr-Zion 345	MISO	MISO
x	3557	WEC	PleasPrairie-Arcadian138 FLO PleasPrairie-Racine345	MISO	MISO
x	3558	WEC	PleasPrairie-Arcadian345 FLO Zion-Arcanian345	MISO	MISO
x	3560	WEC	Whitewater-Mukwonago FLO CherryVal-SilvrLk345	MISO	MISO
x	3570	WEC, CE	Pleasant Prairie-Zion 345 flo Cherry Valley-Silver Lake 345 R	PJM	PJM
x	3571	WEC, CE	Pleasant Prairie-Zion 345 flo Zion-Arcadian 345	PJM	PJM
x	3572	WEC, CE	Pleasant Prairie-Zion 345 flo Zion-Arcadian 345 + Op Guide	PJM	PJM
x	3601	ALTE,WPS	ARPIN - ROCKY RUN 345 KV	MISO	MISO
x	3602	WPS,WEC	ROCKY RUN - N APPLETON 345 KV	MISO	MISO
x	3604	WPS,ALTE	N FOND DU LAC-AVIATION 138 KV	MISO	MISO
x	3705	ALTW	Arnold-Hazelton 345 for Wemp-Paddock 345	MISO	MISO
x	3706	ALTW	Arnold - Hazleton	MISO	MISO
x	3711	ALTW	Albany 161-138 for Nelson-Cordo B 345	MISO	MISO
x	3715	ALTW, CE	Quad Cities-Rock Creek 345/MEC Cordova-Sub 39	PJM	PJM
x	3716	ALTW	Rock Creek 345/161 TR for Quad-Sub 91 345	MISO	MISO
x	3719	ALTW	Salem 345/161 Quad Cities-Sub 91	MISO	MISO
x	3720	ALTW	Salem 345/161 TR for MEC Cordova-Sub 39 345kV	MISO	MISO
x	3721	ALTW	Salem 345/161 for Quad-Sub 91 TR	MISO	MISO
x	3723	ALTW	Tiffon-D.Arnold 345 for Hills-Montezuma 345kV	MISO	MISO
x	3732	ALTW	Arnold-Hazelton 345 (flo) Dorsey-Forbes 500	MISO	MISO

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3736	ALTW	Salem 345/161 flo Wempletown-Paddock 345	MISO	MISO
x	3740	ALTW,CE	Albany-Garden Plain 138 flo Quad Cities-H471 345	PJM	PJM
x	3749	ALTW	Arnold-Hazelton 345 (flo) Montezuma-Bondurant 345	MISO	MISO
x	6009	NPPD, MPS, AECI, OPPD	COOPER_S	MAPP	MISO
x	6074	MEC	Sub 91 345/161kV XFMR FLO Sub 91-Sub 56 345kV	MAPP	MISO
x	6081	MEC	Quad City West 345kV	MAPP	MISO
x	6084	MEC	East Moline 345/161 XFMER (flo) Quad Citites - Sub 91	MAPP	MISO
x	6086	MEC	Montezuma-Bondurant 345kV	MAPP	MISO
x	6088	DPC,NSP	Genoa-Seneca (flo) Eau Claire-Arpin	MAPP	MISO
x	6105	ALTW, CE	Quad Cities - Rock Creek	PJM	PJM
x	6117	MEC	Sub 92-Hills flo Sub 93-Sub T-Hills	MAPP	MISO
x	6124	MEC,ALTW	Sub K/Tiffin-Arnold 345kV	MAPP	MISO
x	6136	CE, MEC	Quad Cities-Sub 91 345 flo Quad Cities-Rock Creek 345	PJM	PJM

MISO Coordinated Flowgates

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	12	PJM,NYIS	Warren-Falconer 115 kV line	TBD	TBD
	13	PJM,NYIS	Erie East-South Ripley 230 kV line	TBD	TBD
	18	PJM,NYIS	Homer City-Watercure Road 345 kV l	TBD	TBD
	20	PJM	Erie West-Erie South 345 kV line	TBD	TBD
	21	PJM	Erie West 345/115 kV xfmr l/o Erie West-Erie South 345 kV	TBD	TBD
	22	PJM	Erie West-Erie South 345 kV l/o Ho 318.1	TBD	TBD
	100	PJM	Kammer #8 xfmr l/o Belmont-Harrison 500	TBD	TBD
	101	PJM,AEP	Kammer #8 xfmr l/o Kammer-South Canton 765 kV line	TBD	TBD
	110	PJM	Wylie Ridge #7 tx l/o Wylie #5 tx (WK3 CB open - OP Proc.)	TBD	TBD
	111	PJM,FE	Sammis-Wylie Ridge 345 kV line l/o Perry-Ashtabula-Erie West	TBD	TBD
	112	PJM,FE	Sammis-Wylie Ridge 345 kV line l/o Belmont-Harrison 500 kV	TBD	TBD
	200	AEP	Tidd-Canton Central 345 kV line l/o Kammer-South Canton 765	TBD	TBD
	205	AEP,FE	Sammis-South Canton 345 kV line l/o Tidd-Canton Central 345	TBD	TBD
	1001	AECI,AMRN	FptLatlatStr	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	1002	AECI,AMRN	ThmMobThoMcc	TBD	TBD
	1003	AECI,AMRN	ThmMobThmSal	TBD	TBD
	1004	AECI,AMRN	MccTieAECAMRN	TBD	TBD
	1005	AECI,AMRN	MarXfrBlaFra	TBD	TBD
	1010	AECI,AMRN	MccTieAMRN AEC	TBD	TBD
	1011	AMRN,AECI	PalXfrPalSub	TBD	TBD
	1014	AECI,AMRN	Lutsvle-Essx-NMadrid for loss of Bland Franks	TBD	TBD
	1015	AECI	Fairport-Lathrop for the loss of StJoe-Hawthorne(LakeRd-Nashua)	TBD	TBD
	1016	AECI	Lutesville-Essex for the loss of Wilhelmina-NewMadrid &	TBD	TBD
	1017	EES,AECI,AMRN	NewMadrid-Dell for loss of Shelby-Lagoon Creek	TBD	TBD
	1018	EES,AECI,AMRN	NewMadrid-Dell for loss of Ises-Dell	TBD	TBD
	1019	EES,AECI,AMRN	NewMadrid-Dell for loss of Tiptonville	TBD	TBD
	1020	AECI	New Madrid 345/500 #1 for Loss of MarshallCumberland500	TBD	TBD
	1021	AECI	New Madrid 345/500 #1 for Loss of Shelby-LagoonCrk500	TBD	TBD
	1201	SOCO,DUK,SC,SCEG	VACAR-SOUTHERN	TBD	TBD
	1203	DUK,AEP	8ANTIOCH 500 05J.FERR 500	TBD	TBD
	1205	DUK,SOCO	8OCONEE 500 8NORCROS 500	TBD	TBD
	1318	EES,OKGE	RusselvilleS-DardanelleDam for los	TBD	TBD
	1320	EES,OKGE	ANO-FtSmith for loss of ANO500-161	TBD	TBD
	1321	EES,OKGE	ANO-FtSmith for loss of Pleasant Hill-ANO	TBD	TBD
	1340	EES	Sheridan-WhiteBluff for loss of Ma	TBD	TBD
	1351	EES,AECI	NewMadrid-Dell	TBD	TBD
	1352	EES	ISES-Dell	TBD	TBD
	1354	EES	RayBraswell-Lakeover	TBD	TBD
	1358	EES	McAdams-LakeOver	TBD	TBD
	1365	EES	West Memphis - Birmingham Steel for the loss of Dell - Shelby	TBD	TBD
	1366	EES,AECI,AMRN	NewMadrid-Dell for loss of Marshall-Cumberland	TBD	TBD
	1367	EES,AECI,AMRN	NewMadrid-Dell for loss of Shawnee-Marshall	TBD	TBD
	1377	AECI,AMRN	Fairport-Lathrop for loss of Iatan-Stranger (LakeRoad-Nashua OpGuide)	TBD	TBD
	1382	EES	Hayti - Blytheville for the loss o	TBD	TBD
	1385	EES	Webre Richard for the loss of Perr	TBD	TBD
	1397	EES	Dell - Shelby for the loss of West Memphis - Birmingham	TBD	TBD
	1501	SOCO,TVA	Conasaga - Sequoyah 500	TBD	TBD
	1504	SOCO,TVA	Miller500-Bellefonte#2&MillerLowndes	TBD	TBD
	1505	SOCO,TVA	Miller-Lowndes500&Daniel-McKnight	TBD	TBD
	1510	SOCO,DUK	8NORCROS 500 80CONEE 500 1	TBD	TBD
	1544	SOCO	Lexington-Russell flo Norcross-Oco	TBD	TBD
	1605	TVA	Shawnee - Clinton 161	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	1609	TVA	Shawnee - C37A 161	TBD	TBD
	1611	TVA	Shawnee - Coleman 161	TBD	TBD
	1612	TVA	Shawnee 161/500 Transformer	TBD	TBD
	1613	TVA	Volunteer - Phipps Bend 500	TBD	TBD
	1615	TVA	Shawnee-Clinton161&Shawnee161/500t	TBD	TBD
	1616	TVA	Shawnee-C31161&Joppa-CapeGireadu161	TBD	TBD
	1617	TVA,SOCO	SNP-Consauga&Oconee-Norcross	TBD	TBD
	1620	TVA	Cumbland-Davidson&Cumbland-Jvill	TBD	TBD
	1621	TVA	Cumbland-Jvill&Cumbland-Davidson	TBD	TBD
	1622	TVA,LGEE	Paddys Run-Summershade 161 (flo) Broadford-Sullivan 500	TBD	TBD
	1623	TVA,LGEE	Paddys Run-Summershade 161 (flo) Paradise-Montgomery 500 kV	TBD	TBD
	1627	TVA,EKPC	Wolf Crk-Russell&PhippsBnd-Pocket	TBD	TBD
	1631	TVA,LGEE	Pinevil-Pinevil&PhippsBnd-Pocket	TBD	TBD
	1632	TVA,LGEE	Pinevil-Pinevil&Volunteer 500/161	TBD	TBD
	1634	TVA	Volunteer-Bull Run&WBN-Volunteer	TBD	TBD
	1635	TVA	Marshall Bank	TBD	TBD
	1638	TVA,EES	Shelby-Dell 500-kV	TBD	TBD
	1639	TVA,LGEE	Kentucky-Livingston 161-kV	TBD	TBD
	1640	TVA,LGEE	Calvert-Livingston 161-kV	TBD	TBD
	1641	TVA	Volunteer-PhippsBend 500 for Loss of Volunteer 500/161	TBD	TBD
	1642	BREC	Henderson138/161 flo Culley-Grandview138	TBD	TBD
	1643	TVA	Volunteer500/161 FLO VolunteerPhippsBend 500	TBD	TBD
	1644	TVA	Bull Run - Volunteer 500kV	TBD	TBD
	1701	PJM,VAP	01PRNTY 500 8MT STM 500	TBD	TBD
	1706	VAP,AEP	CLOVERDALE-LEXINGTON 500	TBD	TBD
	1707	CPLE,VAP	WAKE-CARSON 500	TBD	TBD
	1722	VAP	Clover 230-500 Trans./Wake-Carson	TBD	TBD
	2004	AEP	05MARYSV 765 05MARYSV 345 1	TBD	TBD
	2005	AEP	05MARYSV 05E LIMA 345-MARYSV SWLIMA 345	TBD	TBD
	2006	AEP	05SCANTO 765 05SCANTO 345 1	TBD	TBD
x	2007	AEP	05COOK 765 05COOK 345 1	AEP	PJM
x	2008	AEP	05DUMONT 765 05DUMTEQ 999 1	AEP	PJM
	2009	AEP	05COOK 345 05BENTON 345 1	TBD	TBD
	2010	AEP,MECS	05COOK 345 18PALISA 345 1	TBD	TBD
	2011	AEP,MECS	05ROB PK 345 18ARGENT 345 1 -147.2	TBD	TBD
	2012	AEP,MECS	05TWIN B 345 18ARGENT 345 1	TBD	TBD
x	2014	AEP,CE	05OLIVE 345 UPNOR;RP 345 1	AEP	PJM
x	2015	AEP,CE	05OLIVE 345 G ACR; T 345 1	AEP	PJM
	2016	AEP	05FALL C 345 05DESOTO 345 1	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	2017	AEP	05COOK 345 05OLIVE 345	AEP	PJM
	2018	AEP	05DARWIN 345 05EUGENE 345 1	TBD	TBD
	2019	AEP	05BREED 345 05DEQUIN 345 1	TBD	TBD
	2020	OVEC,AEP	06KYGER 345 05SPORN 345 1	TBD	TBD
	2021	HE,CIN	07MEROM5 345 08DRESSR 345 1	TBD	TBD
	2022	HE,CIN	08GIBSON 345 07MEROM5 345 1	TBD	TBD
	2023	HE,CIN	07BLOMNG 345 08BLOOM 230 1	TBD	TBD
	2024	HE,SIGE	07NWTNVL 161 10NEWTVL 161	TBD	TBD
	2025	HE,IPL	Ratts-Petersburg 138	TBD	TBD
	2026	SIGE,BREC	10NEWTVL 161 14COLE 5 161	TBD	TBD
	2029	CIN,AEP	08HNTNGT 138 05HUNT J 138 1	TBD	TBD
	2030	CIN,AEP	08NOBLSV 345 05FALL C 345 1	TBD	TBD
	2031	CIN,AEP	Dequine-Westwood 345 flo Cayuga-Ve	TBD	TBD
x	2032	CIN, AEP	Cayuga-Eugene 345 (flo) Cayuga-Nucor 345	MISO	MISO
	2033	CIN, AEP	New Castle-Fall Creek 138 (flo) Fall Creek 345/138 XFMR	TBD	TBD
	2034	AEP,CIN	Greentown 765/230/138 Xfm flo Greentown-Dumont 765	TBD	TBD
	2035	AEP,CIN	05GRNTWN 765 08GRNTWN 138 1	TBD	TBD
	2037	AEP,CIN	05STANNER 345 08M.FTHS 345 1	TBD	TBD
	2038	AMRN,CIN	LAWRNCVL 138 08VIN 138 1	TBD	TBD
	2040	DPL,CIN	09STUART 345 08FOSTER 345 1	TBD	TBD
	2041	DPL,CIN	Foster-Sugar Creek 345	TBD	TBD
	2042	HE,CIN	07NAPOL8 138 08BATESV 138 1	TBD	TBD
	2043	HE,CIN	07WORTH8 138 08HEOWEN 138	TBD	TBD
	2044	IPL,CIN	16PETE 138 08OKLND 138	TBD	TBD
	2045	IPL,CIN	16PETE 138 08VIN J 138 1	TBD	TBD
	2046	IPL,CIN	Petersburg-Lost River 345 flo Gibson-Bedford 345	TBD	TBD
	2047	IPL,CIN	Gibson-Petersburg 345 flo Gibson-Bedford 345	TBD	TBD
	2048	IPL,CIN	16SUNNYS 345 08GWYNN 345 1	TBD	TBD
	2049	LGEE,CIN	12GHENT 345 08BATESV 345 1	TBD	TBD
	2050	LGEE,CIN	08SPEED 345 12GHENT 345 1	TBD	TBD
	2051	LGEE,CIN	11JEFFJC 138 08JEFF 138 1	TBD	TBD
	2052	LGEE,CIN	Speed-Northside 138 flo Speed-Ghent 345	TBD	TBD
	2053	LGEE,CIN	Gallagher-Paddys West 138 flo Rock 114.5	TBD	TBD
	2055	OVEC,CIN	Pierce-Foster 345 flo Stuart-Foster 345	TBD	TBD
	2056	CIN,AMRN	08GIBSON 345 ALBION 345 1	TBD	TBD
	2057	CIN,DPL	Miami Fort-West Milton 345 flo Foster-Sugarcreek 345	TBD	TBD
	2059	CIN,EKPC	08BUFTN1 138 20BOONE 138 1	TBD	TBD
	2060	CIN,HE	08BLOOM 230 07BLOMNG 345 1	TBD	TBD
	2061	CIN,HE	08LINTON 138 07WORTH8 138 1	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2062	CIN,IPL	085PTBK1 138 16FVE_T 138 1 40.8	TBD	TBD
	2063	CIN,IPL	Whitestown-Guion 345 (flo) Whitestown-Hortonville 345	TBD	TBD
	2064	CIN,LGEE	11GHENT 138 08FAIRW 138 1	TBD	TBD
	2068	CIN,OVEC	06PIERCE 345 08BKJ135 138 1	TBD	TBD
	2069	CIN,OVEC	08BUFTN1 345 06DEARB2 345 1	TBD	TBD
	2070	CIN,OVEC	08BUFTN1 345 06PIERCE 345 1	TBD	TBD
	2071	CIN,SIGE	08OKLND 138 10TOYOTA 138 1 125.4	TBD	TBD
	2072	CIN	New London-Webster 230 flo Jefferson-Greentown 765	TBD	TBD
	2073	CIN,DPL	Foster-Sugar Creek 345 (flo) Stuart-Clinton 345	TBD	TBD
	2074	DPL	09STUART 345 09CLINTO 345 1	TBD	TBD
	2077	SIGE,BREC	10ABBRWW 138 14HENDR4 138 1	TBD	TBD
	2078	SIGE,IPL	Cato-Petersburg 138	TBD	TBD
	2079	SIGE,CIN	10TOYOTA 138 08OKLND 138 1 -125.4	TBD	TBD
	2083	SIGE	Culley-Grandview 138	TBD	TBD
	2084	SIGE	Northeast-Elliot 138	TBD	TBD
	2085	SIGE	Culley-Grimm 138	TBD	TBD
	2086	SIGE	10NEWTVL 161 10NEWTVL 138 1	TBD	TBD
	2087	SIGE	A.B. Brown-Northeast 138	TBD	TBD
	2088	SIGE	Culley-Dubois 138	TBD	TBD
	2089	OVEC,LGEE	06CLIFTY 345 11TRIMBL 345 1	TBD	TBD
	2092	LGEE	11CLVRPR 138 12G R ST 138 1	TBD	TBD
	2093	LGEE	11CLVRPR 138 12HARDBG 138 1	TBD	TBD
	2095	LGEE,BREC	11CLVRPR 138 14N.HAR4 138 1	TBD	TBD
	2096	LGEE,EKPC	Blue Lick-Bullitt County 161 (flo) Trimble-Clifty Creek 345	TBD	TBD
	2097	LGEE,TVA	11PADDYS 161 5SUMMER 161 1	TBD	TBD
	2100	BREC	14COLE 5 161 14NATAL5 161 1	TBD	TBD
	2101	BREC	14REID 5 161 14DAVIS5 161 1	TBD	TBD
	2102	BREC,TVA	14HOPCO5 161 5BARKLEY 161 1	TBD	TBD
	2103	IPL	16PETE 345 16THOMPS 345 1	TBD	TBD
	2104	IPL	16PETE 345 16FRANCS 345 1	TBD	TBD
	2105	IPL,AEP	16WHEAT 345 05BREED 345	TBD	TBD
	2106	IPL,AEP	16SUNNYS 345 05FALL C 345 1	TBD	TBD
	2107	IPL,AEP	Tanners Creek-Hanna 345 kV	TBD	TBD
	2131	PJM,FE	Sammis-Wylie Ridge 345	TBD	TBD
	2132	PJM,FE	KRENDALE-SENECA 138 FLO CABOT-WYLIE RIDGE 500	TBD	TBD
	2133	PJM,AEP	01BELMNT 500 05BELMON 765 1	TBD	TBD
	2134	PJM,AEP	Wylie Ridge-Tidd 345 kV line	TBD	TBD
	2135	PJM,AEP	01KAMMER 500 05KAMMER 765 1	TBD	TBD
	2137	PJM,DLCO	01MITCHL 138 15ELRM 3 138 1	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2141	FE,DLCO	02SAMMIS 345 15BVRVAL 345 1	TBD	TBD
	2184	FE,MECS	Bay Shore-Monroe 345 flo Lemoyne-Majestic 345	TBD	TBD
	2185	FE,MECS	LEMOYNE-MAJESTIC 345 flo BAY SHORE-MONROE 345	TBD	TBD
	2186	FE,MECS	Allen-Lulu 345	TBD	TBD
	2187	LGEE	12W LEXI 345 12W LEXI 138 1	TBD	TBD
	2188	LGEE	12W LEXI 345 12BRWN N 345 1	TBD	TBD
	2189	LGEE	12BRWN N 345 12BRWN N 138 1	TBD	TBD
	2190	LGEE	12BRWN N 345 12ALCALD 345 1	TBD	TBD
	2191	LGEE	12ALCALD 345 12ALCALD 161 1	TBD	TBD
	2192	LGEE	Pineville 500/345 Tr. 138	TBD	TBD
	2193	LGEE,TVA	12POCKET 500 8PHIPP B 500 1	TBD	TBD
	2194	BREC	14N.HAR4 138 14N.HAR5 161	TBD	TBD
	2195	AEP,DPL	CENTRAL OHIO	TBD	TBD
	2196	LGEE	Blue Lick 345/161 XFMR	TBD	TBD
	2197	OVEC,AEP	Kyger-Sporn345 for Amos 765/345XFMR	TBD	TBD
	2198	LGEE	Blue Lick 345/161 XFMR-Baker-Broadford	TBD	TBD
	2199	LGEE	Ghent-W.Lexington 345kV-Baker-Broadford	TBD	TBD
	2200	LGEE	Brown-Lebanon 138 kV	TBD	TBD
	2201	LGEE	Brown South-Fawkes 138 kV	TBD	TBD
	2202	OVEC,AEP	Kyger-Sporn345 for Baker-Broadford 765	TBD	TBD
	2203	CIN	BUFFINGTON_345_138_PIERCE_FOSTER_345	TBD	TBD
	2209	LGEE	W.Lex-E.W.Brown345 / Baker-Broadford765kv	TBD	TBD
	2210	LGEE	Knob Creek-Pond Creek 138 flo Baker-Broadord 765	TBD	TBD
x	2213	NIPS,CE	State Line-Wolf Lake 138 flo Dumont 765/345 Tr	MISO	MISO
x	2214	NIPS,CE	State Line-Wolf Lake 138 flo UP North-Olive 345	MISO	MISO
x	2215	NIPS,CE	State Line-Wolf Lake 138 flo SLINE;5S-WASHI; R 138	MISO	MISO
	2216	NIPS,AEP	New Carlisle-Trail Creek 138 flo Olive-Green Acre 345	TBD	TBD
	2217	NIPS,AEP	New Carlisle-Trail Creek 138 flo Olive-UPNOR:RP 345	TBD	TBD
	2218	NIPS,AEP	New Carlisle-Trail Creek 138 flo D	TBD	TBD
	2220	NIPS,AEP	New Carlisle-Maple 138 flo Dumont-	TBD	TBD
x	2221	NIPS,CE	Munster-Burnham 345 flo Olive-University Park North 345	MISO	MISO
	2222	NIPS,AEP	Kline-Northeast 138 flo Olive-Gree	TBD	TBD
x	2223	NIPS,AEP	Dumont-Stillwell 345 flo Olive-Green Acre 345	MISO	MISO
	2225	NIPS,CIN	Deedsville-Leesburg 345 flo Dumont 345/138 Tr	TBD	TBD
	2228	NIPS	Hiple 345/138 Tr flo Goshen Jct-Hi 217.3	TBD	TBD
	2230	NIPS	East Winamac-Burr Oak 138 flo Oliv	TBD	TBD
	2231	NIPS,AEP	Laporte-Michigan City 138 flo Dumont-Stillwell 345	TBD	TBD
	2232	NIPS	Michigan City-Trail Creek 138 flo Olive-Green Acre 345	TBD	TBD
	2233	NIPS	Michigan City-Trail Creek 138 flo Dumont-Stillwell 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2234	NIPS	Monticello-East Winamac 138 flo Du	TBD	TBD
	2236	FE,MECS	ALLEN-LULU 345 flo BAY SHORE-MONROE 345	TBD	TBD
	2237	FE	BAY SHORE-TOUSSAINT 138 flo DAVIS BESSE-BEAVER 345	TBD	TBD
	2238	FE	GREENFIELD-LAKEVIEW 138 flo BEAVER-DAVIS BESSE 345	TBD	TBD
	2239	FE,AEP	LEMOYNE-FOSTORIA 345 flo BAY SHORE-FOSTORIA 345	TBD	TBD
	2240	FE	Toussaint-Ottawa 138 flo Davis Besse-Beaver 345	TBD	TBD
	2241	MECS,FE	MONROE-BAY SHORE 345 FLO LULU-ALLEN 345	TBD	TBD
	2242	FE	BAY SHORE 345/138 TR FLO LULU 3-TERMINAL LINE 3	TBD	TBD
	2244	LGEE,TVA	Paddys-Summershade 161 flo Baker-Broadford 765	TBD	TBD
	2245	LGEE,EKPC	Blue Lick-Bullitt Co 161 flo Baker-Broadford 765	TBD	TBD
	2246	FE,MECS	Bay Shore-Monroe 345 flo Lemoyne-Davis Besse 345	TBD	TBD
	2247	FE	Beaver-Brookside 138 flo Beaver-Da 17.8	TBD	TBD
	2248	FE	Davis Besse-Beaver 345 flo Kammer-S Canton 765	TBD	TBD
	2249	FE,AEP	Brookside-Howard 138 flo Beaver-Davis Besse 345	TBD	TBD
	2250	FE	Hoyt-Maple 138 flo Sammis-Wylier 345	TBD	TBD
	2251	FE	Hoyt-Maple 138 flo Wylie Ridge-Cabot 500	TBD	TBD
	2255	FE,DPL	Kirby-Bluejacket 138 flo Mill Cree	TBD	TBD
	2256	FE	Mansfd-Highland 345 flo Mansfd-Hoytdl 345	TBD	TBD
	2257	FE,DLCO	Mansfd-Bvrval 345 #2 flo Mansfd-Crescent 345	TBD	TBD
	2258	FE	Richln-Ridgeville 138 flo Midw-Richln-Waus 138	TBD	TBD
	2259	FE,PJM	Sammis-Wylier 345 flo Kam-Har-FtM 3-Term line 500	TBD	TBD
	2260	FE,PJM	Wylie Ridge-Sammis 345 flo Kammer-S Canton 765	TBD	TBD
	2261	FE,PJM	Sammis-Wylier 345 flo Sammis-S Canton 345	TBD	TBD
	2262	FE	Sammis-Highland 345 flo Sammis-Bvrval 345	TBD	TBD
	2263	FE	Sammis-Star 345 flo S Canton-Star 345	TBD	TBD
	2264	FE	Star-Carlil 345 flo Avon-Juniper 345	TBD	TBD
	2265	FE	Star-Juniper 345 flo Hanna-Juniper 345	TBD	TBD
	2266	LGEE	Knob Creek-Pond Creek 138 (flo) Ghent-W. Lexington 345	TBD	TBD
	2268	LGEE	Smith-Green River Steel 138 flo Smith 345/138 Xfmr	TBD	TBD
	2269	NIPS	Leesburg-Northeast 138 flo Hiple 345/138	TBD	TBD
	2270	FE	Perry-Ashtabula 345 (flo) Wylie Ridge-Cabot 500	TBD	TBD
	2271	IPL,AEP	Wheatland-Breed 345 (flo) Rockport-Sullivan 765	TBD	TBD
	2272	LGEE,CIN	Ghent-Batesville 345 (flo) Ghent-W. Lexington 345	TBD	TBD
	2273	SIGE	A. B. Brown-Northwest 138 flo A. B. Brown-Henderson 138	TBD	TBD
	2276	FE	Star-Carlisle 345 flo Star-Juniper 345	TBD	TBD
	2277	EKPC, LGEE	Avon-Loudon 138 flo Ghent-West Lexington-Brown 345	TBD	TBD
	2278	FE	Avon-Beaver 345 #1 flo Avon-Beaver 345 #2	TBD	TBD
	2279	LGEE	Paddys West-Paddys Run 138 (flo) Cane Run-Cane Run 6 138	TBD	TBD
	2280	FE, AEP	Bay Shore-Fostoria 345 flo Lemoyne-Fostoria 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2281	SIGE	Newtonville 138/161 flo Henderson 138/161	TBD	TBD
	2282	FE	Beaver-Davis Besse 345 flo Galion-Fostoria 345	TBD	TBD
	2283	CIN	Bloomington-Denois Creek 230 flo Bedford-Columbus 345	TBD	TBD
	2284	LGEE, EKPC	Blue Lick-Bullitt Co. 161	TBD	TBD
	2285	LGEE	Paddys West - Paddys Run 138	TBD	TBD
x	2286	CE, NIPS	Burnham-Munster 345 flo Dumont-Wilton Center 765	MISO	MISO
x	2287	CE, NIPS	Burnham-Munster 345 flo Dumont-Wilton Center 765 + Op G	MISO	MISO
x	2288	CE, NIPS	Burnham-Sheffield 345 flo Dumont-Wilton Center 765	MISO	MISO
	2289	DLCO, FE	Beaver Valley-Hanna 345 flo Mansfield-Chamberlin 345	TBD	TBD
	2290	DLCO, FE	Beaver Valley-Sammis 345 flo Beaver Valley-Hanna 345	TBD	TBD
	2291	IPL,CIN	Petersburg-Oakland City 138 flo Gi 99.7	TBD	TBD
	2292	FE	Chamberlin-Harding 345 flo Star-Juniper 345	TBD	TBD
	2293	LGEE,CIN	Gallagher - Paddys West 138 (flo) 15.0	TBD	TBD
	2294	OVEC, LGEE	Clifty Creek-Carrollton 138 flo Baker-Broadford 765	TBD	TBD
	2295	SIGE,BREC	A. B. Brown-Henderson 138 flo Culley-Grandview 138	TBD	TBD
x	2296	CE,NIPS	Munster-Burnham 345 flo University Park North-E. Frankfort 345	MISO	MISO
x	2298	AEP,NIPS	New Carlisle-Trail Creek 138 flo University Park North-E. Frankfort 345	MISO	MISO
x	2299	AEP, NIPS	Dumont-Stillwell 345 flo Dumont-Wilton Center 765	AEP	PJM
	2304	PJM	01HATFLD 500 01YUKON 500 1	TBD	TBD
	2305	PJM	01WYLIER 500 O1CABOT 500 1	TBD	TBD
	2306	PJM	Wylie Ridge #5 345/500 kV xfmr	TBD	TBD
	2307	PJM	Wylie Ridge #7 345/500 kV xfmr	TBD	TBD
	2314	FE	DAVIS BESSE-BAY SHORE 345 flo DAVIS BESSE-LEMOYNE 345	TBD	TBD
	2315	FE	DAVIS BESSE-LEMOYNE 345 flo DAVIS BESSE-BAY SHORE 345	TBD	TBD
	2316	FE	ALLEN 345/138 Tr flo MONROE-BAY SHORE 345	TBD	TBD
	2317	FE	Bay Shore 345/138kV Tr	TBD	TBD
	2330	AEP	05BROADF 765 05J.FERR 765 1	TBD	TBD
	2331	AEP	05BAKER 765 05BROADF 765 1	TBD	TBD
	2332	AEP	05J.FERR 765 05CLOVRD 765 1	TBD	TBD
	2333	AEP	05KAMMER 765 05BELMON 765 1	TBD	TBD
	2334	AEP	05BELMON 765 05MOUNTN 765 1	TBD	TBD
	2336	AEP,MECS	BentnHrbr-Palisades345/Cook-Palisades345	TBD	TBD
	2337	AEP,MECS	Cook-Palisades345/BentnHrbr-Palisades345	TBD	TBD
	2338	MECS,AEP	Cook-Palisades345/TwinBranch-Argenta345	TBD	TBD
	2339	MECS,AEP	BentnHrbr-Palisades345/TwinBranch-Argenta345	TBD	TBD
	2340	MECS,AEP	TwinBranch-Argenta345/Cook-Palisades345	TBD	TBD
	2341	MECS,AEP	TwinBranch-Argenta345/Robison Pk-Argenta 345	TBD	TBD
	2350	PJM,AEP	BELMNT500/765TX-KAMMER500/765TX	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2351	PJM,AEP	KAMMER500/765TX-BELMNT500/765TX	TBD	TBD
	2352	PJM,VAP	PRNTY-MTSTM500/BLACKO-BEDNGT500	TBD	TBD
	2353	PJM	BLACKO-BEDNGT500-PRNTY-MTSTM500	TBD	TBD
	2356	PJM,VAP	PRNTY-MTSTM500-HATFIELD-BLACKO500	TBD	TBD
	2357	PJM	Wylie Ridge #7 345/500 xfmr l/o Wylie Ridge #5 345/500 xfmr	TBD	TBD
	2358	PJM	Wylie Ridge #5 345/500 xfmr l/o Wylie Ridge #7 345/500 xfmr	TBD	TBD
	2365	PJM	FT MARTN-PRNTY500/HARRSN-PRUNTY500	TBD	TBD
	2366	PJM,DLCO	MITCH-ELRAMA138/SAMMIS-WYLIER345	TBD	TBD
	2367	PJM,DLCO	MITCH-ELRAMA138/WYLIER-CABOT500	TBD	TBD
	2368	PJM,FE	SAMMIS-WYLIE RIDGE 345 FLO KAMMER 765/345 TR	TBD	TBD
	2369	PJM,AEP	Tidd-Wylie Ridge 345 kV line l/o Kammer 765/500 kV xfmr	TBD	TBD
	2370	PJM	BEDINGTON-DOUBS500/PRUNTY-MT STM50	TBD	TBD
	2371	PJM	Wylie Ridge #7 345/500 xfmr l/o Kammer 765/500 kV xfmr	TBD	TBD
	2372	PJM	Wylie Ridge #7 345/500 xfmr l/o Harrison-Wylie Ridge 500 kV	TBD	TBD
	2373	PJM	Wylie Ridge #7 345/500 xfmr l/o Belmont-Harrison 500 kV	TBD	TBD
	2374	PJM	Wylie Ridge #5 345/500 xfmr l/o Harrison-Wylie Ridge 500 kV	TBD	TBD
	2375	PJM	Wylie Ridge #5 345/500 xfmr l/o Belmont-Harrison 500 kV	TBD	TBD
	2376	PJM,VAP	PRNTY-MTSTM500/BEDINGTON-DOUBS500	TBD	TBD
x	2400	AEP	DUMONT765-345TX-COOK765-345TX	AEP	PJM
x	2401	CE,AEP	DUMONT765/345TX-DUMONT WILTON C 765	AEP	PJM
x	2402	AEP	COOK765-345TX-DUMONT765-345TX	AEP	PJM
	2403	AEP	KANAWZ-M FUNK 345/BAKER-BROADFORD 765	TBD	TBD
	2404	AEP	KANAWZ-M FUNK 345/BROADFORD-JFERRY	TBD	TBD
	2405	AEP	Kammer-W Belair 345/Kammer-S Canton 765	TBD	TBD
	2412	AEP	Waterford-Muskingum 345 kv / Mountaineer-Belmont 765 kv	TBD	TBD
	2413	AEP	S. Canton 765/345 kv Xfmr / Tidd-Canton Central 345 kv	TBD	TBD
	2414	AEP	S. Canton 765/345 kv Xfmr / Marysvl 765/345 kV Xfmr	TBD	TBD
	2415	AEP	S. Canton 765/345 kV Xfmr / Kammer 765/500 kV Xfmr	TBD	TBD
	2416	AEP	Muskingum River-Ohio Central 345 kV / E Lima-Fostoria 345 kV	TBD	TBD
	2417	AEP,DUK	J Ferry-Antioch 500kV / Broadford-Sullivan 500 kV	TBD	TBD
	2420	BREC,LGEE	COLEMN-NATAL 161/WILSN-GRN RVR 161	TBD	TBD
	2421	BREC,TVA,LGEE	HOPKIN CO-BARKLEY 161/WILSN-GRN RV	TBD	TBD
	2422	BREC	NEW HARDINSBG 138-161/COLEMN-NATAL 161	TBD	TBD
	2423	BREC,TVA	Hardinsburg-Paradise 161 kV	TBD	TBD
	2424	BREC,TVA	BRYAN / MARSHALL 161 KV	TBD	TBD
	2452	CIN	08SPEED 345/138 11GHENT 345 11W LEXN 345	TBD	TBD
	2454	CIN	Sugar Creek-Cayuga CT 345 flo Wheatland-Amo 345	TBD	TBD
	2455	CIN	Gibson 345/138	TBD	TBD
	2456	CIN	Gibson 345/138 Gibson Pete 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2457	CIN	Cayuga 345/230 XFMR 9 (flo) Cayuga 345/230 XFMR 10	TBD	TBD
	2460	CIN	08CAYUGA VDSBRG 230 08CAYUGA FRNKFT 230	TBD	TBD
	2461	CIN	08GIBSON WHEAT 345 08GIBSON 16PETE 345	TBD	TBD
	2462	CIN	Wheatland-Amo 345 flo Gibson-Petersburg 345	TBD	TBD
	2464	CIN	Frankfort-New London 230 flo Veedersburg-Cayuga 230	TBD	TBD
	2465	CIN	Speed-Ramsey 345 Buckner - Middletown 345	TBD	TBD
	2466	CIN	Zimmer to Port Union 345 kV	TBD	TBD
	2468	NIPS,AEP	Trail Creek-New Carlisle	TBD	TBD
	2470	FE,PJM	Ashtabula-Erie West 345 (flo) Sammis-Wylie Ridge 345	TBD	TBD
	2471	FE	Avon-Beaver #2 345 (flo) Avon-Beaver #1 345	TBD	TBD
	2472	FE	Chamberlin 345/138 (flo) Chamberlin-Harding 345	TBD	TBD
	2473	FE,DPL	Greene-Clark 138 (flo) Urbana-Clark 138	TBD	TBD
	2474	FE	East Lake 345/138 (flo) Perry-Inland 345	TBD	TBD
	2475	FE	Galion 345/138 TR1 (flo) Galion 345/138 TR2	TBD	TBD
	2476	FE	Mansfield-Chamberlin 345 (flo) Beaver Valley-Hanna 345	TBD	TBD
	2477	FE	Perry-Ashtabula 345 (flo) East Lake 345/138 TR 61	TBD	TBD
	2478	FE,PJM	Ashtabula-Erie West 345(flo) Mansfield-Chamberlin 345	TBD	TBD
	2479	FE	Carlisle-Lorain 138 (flo) Carlisle-Beaver 345	TBD	TBD
	2480	LGEE	TRIMBLE COUNTY - CENTERFIELD 138 K	TBD	TBD
	2481	LGEE	11TRIMBL 345 11TRIMBL 138	TBD	TBD
	2482	LGEE,EKPC	Marion 138/161 kv xfmr	TBD	TBD
	2483	EKPC,LGEE	Avon - Loudon 138 kV	TBD	TBD
	2484	LGEE,OVEC	Northside-Clify Creek 138 (flo) Trimble Co.-Clifty Creek 345	TBD	TBD
	2485	LGEE,CIN	Gallagher-Paddys West 138 (flo) Tr -33.7	TBD	TBD
	2486	LGEE,CIN	Speed-Northside 138 (flo) Trimble Co.-Clifty Creek 345	TBD	TBD
	2488	LGEE,EKPC	11BLUE L 161 20BLIT C 161 1 flo 11GHENT 345 11W LEXN 345	TBD	TBD
	2490	FE	Lorain-Johnson 138 (flo) Avon 345/138 TR	TBD	TBD
	2493	FE,DLCO	Beaver Valley 1-Mansfield 345 (flo) Beaver Valley 2-Mansfield 345	TBD	TBD
	2494	FE,AEP	East Leipsic-Richland 138 flo East Lima-Robison Park	TBD	TBD
	2495	FE,AEP	Richland-Lockwood 138 flo East Lima-Robison Park 345	TBD	TBD
	2496	FE,AEP	Canton Central-Cloverdale 138 (flo) Torrey-Cloverdale 138	TBD	TBD
x	2497	NIPS	State Line-Wolf Lake 138	MISO	MISO
	2498	FE,AEP	West Canton-Dale 138 (flo) South C	TBD	TBD
	2500	SIGE,LGEE	10NEWTVL-11CLVRPR 138/COLEMN-NATAL 161	TBD	TBD
	2503	FE	Torrey-Cloverdale 138 (flo) Muskingum-Ohio Central-Galion 345	TBD	TBD
	2504	FE	Hanna-Juniper 345 (flo) Mansfield-Chamberlin 345	TBD	TBD
	2505	FE	Perry-Ashtabula 345 (flo) Sammis-W.Ridge 345	TBD	TBD
	2550	IPL	Petersburg 345/138 xfmr (East)	TBD	TBD
	2551	IPL	Petersburg 345/138 xfmr (East) flo Petersburg 345/138 xfmr (West)	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2853	MECS	19001 CVTRY 345-120/MADRD-MAJTC	TBD	TBD
	2854	MECS	CVTRY 345-120/MON34-BRSTNN	TBD	TBD
	2855	MECS	MON12-BNSTNS/MON12-WAYNE	TBD	TBD
	2856	MECS	MON12-WAYNE/MON12-BNSTNS	TBD	TBD
	2859	MECS,FE	BAYSHORE-MONROE 345 FLO ALLEN-LULU 345, LULU-MAJESTIC 345, & LULU-MONROE 345	TBD	TBD
	2861	MECS,FE	Monroe-Bay Shore 345 flo Fostoria-Bay Shore 345	TBD	TBD
	2863	MECS	Argenta-Battle Creek 345 flo Argenta-Tompkins 345	TBD	TBD
	2864	MECS	Argenta-Morrow 138 flo Argenta-Battle Creek 345	TBD	TBD
	2865	MECS	Atlanta Jct.-Atlanta 138 flo Thetford-Jewell 345	TBD	TBD
	2866	AEP, MECS	Cook-Palisades 345 flo Cook-Benton Harbor 345	TBD	TBD
	2867	MECS	Delhi-Tompkins 138 flo Argenta-Tompkins 345	TBD	TBD
	2868	MECS	Detroit Industrial-Waterman 230 flo Detroit Industrial-Navare 230	TBD	TBD
	2869	FE	Eastlake-Juniper 345 flo Perry-Harding 345	TBD	TBD
	2870	LGEE	Northside-Beargrass 138 flo Northside-Jeffersonville Jct. 138	TBD	TBD
	2871	BREC, LGEE	New Hardinsburg-Hardinsburg 138	TBD	TBD
	2872	LGEE	Frankfort East-Tyrone 138 flo Ghent-West Lexington 345	TBD	TBD
	2873	AEP, FE	Fostoria-Lemoyne 345 flo Davis Besse-Lemoyne 345	TBD	TBD
	2874	LGEE	Fawkes-Fawkes Tap 138 flo Fawkes-EKPC Fawkes 138	TBD	TBD
	2875	FE, AEP	Galion-Fostoria 345 flo Beaver-Davis Besse 345	TBD	TBD
	2876	LGEE	Northside-Jeffersonville Jct. 138 flo Northside-Beargrass 138	TBD	TBD
	2878	LGEE	Ghent-Owen County Tap 138 flo Ghent-West Lexington 345	TBD	TBD
	2879	LGEE	Ghent-West Lexington 345	TBD	TBD
	2880	HE	GPC-Ratts 161	TBD	TBD
	2881	LGEE	Grahamville-South Paducah 161	TBD	TBD
	2882	FE	Ottawa-Toussaint 138 flo Beaver-Davis Besse 345	TBD	TBD
	2883	LGEE	Green River-River Queen Tap 161	TBD	TBD
	2884	LGEE	Green River Steel-Cloverport 138 flo Smith-Hardin County 345	TBD	TBD
	2885	LGEE	Haefling-IBM North Jct. 138	TBD	TBD
	2886	MECS	Hemphill-Hunters Creek 120 flo Hampton-Pontiac 345	TBD	TBD
	2887	MECS	Hemphill-Hunters Creek 120 flo Thetford-Jewell 345	TBD	TBD
	2888	MECS	Hampton-Pontiac 345 flo Thetford-Jewell 345	TBD	TBD
	2889	MECS	Island Rd-Canal 138 flo Argenta-Tompkins 345	TBD	TBD
x	2890	CE,NIPS	State Line-Wolf Lake 138 flo E. Frankfort-University Park North 345	MISO	MISO
	2893	PJM, FE	Krendale-Seneca 138	TBD	TBD
	2894	PJM, FE	Krendale-Seneca 138 flo Mansfield-Hoytdale 345	TBD	TBD
	2895	PJM, FE	Krendale-Seneca 138 flo Wylie Ridge-Sammis 345	TBD	TBD
	2896	MECS	Latson-Genoa 138 flo Thetford-Jewell 345	TBD	TBD
	2897	FE, AEP	Lemoyne-Fostoria 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2898	FE	Torrey-Cloverdale 138 (flo) CantonCentral-Cloverdale 138	TBD	TBD
	2899	FE, AEP	Lemoyne-West End 138 flo Lemoyne-Fostoria 345	TBD	TBD
	2900	FE,AEP	Tangy-Hyatt 345 (flo) Marysville-Orange 765	TBD	TBD
	2902	FE	Sammis-Highland 345 (flo) Mansfield-Highland 345	TBD	TBD
	2904	FE, DLCO	Mansfield-Beaver Valley 345 #2 flo Mansfield-Beaver Valley 345 #1	TBD	TBD
	2905	FE	Richland-Ridgeville 138 (flo) Richland-Lockwood 138	TBD	TBD
	2906	FE, DLCO	Mansfield-Crescent 345 flo Beaver Valley-Crescent 345	TBD	TBD
	2907	FE	Mansfield-Hoytdale 345 flo Mansfield-Highland 345	TBD	TBD
	2908	CIN	Miami Fort 345/138 Xfm flo East Bend-Terminal 345	TBD	TBD
	2909	MECS	McGulpin-Riggsville 138 flo McGulpin-Oden 138	TBD	TBD
	2910	LGEE	Middletown 345/138 Xfm #1 flo Middletown 345/138 Xfm #3	TBD	TBD
	2911	LGEE	Middletown-3842 Tap 138 flo Blue Lick 345/138 Xfm	TBD	TBD
	2912	LGEE	Mill Creek-Manslick 138 flo Cane Run 6-Cane Run Switching 138	TBD	TBD
x	2913	NIPS,AEP	Stillwell-Dumont 345	MISO	MISO
	2914	AEP, FE	Marysville-Tangy 345	TBD	TBD
	2915	SIGE, LGEE	Newtonville-Cloverport 138	TBD	TBD
	2916	SIGE, HE	Newtonville-Troy 161	TBD	TBD
	2917	AEP, FE	Ohio Central-Galion 345 flo E. Lima-Fostoria 345	TBD	TBD
	2918	MECS	Oneida-Majestic 345	TBD	TBD
	2919	FE	Ottawa-Lakeview 138 flo Davis Besse-Beaver 345	TBD	TBD
	2920	MECS, AEP	Palisades-Benton Harbor 345 flo Twin Branch-Argenta 345	TBD	TBD
	2921	MECS, AEP	Palisades-Cook 345 flo Twin Branch-Argenta 345	TBD	TBD
	2923	TVA, LGEE	Phipps Bend-Pocket North 500	TBD	TBD
	2925	LGEE, CIN	Ghent-Fairview 138 flo Ghent-Batesville 345	TBD	TBD
	2926	NIPS,AEP	Maple-New Carlisle 138	TBD	TBD
	2927	MECS	Roosevelt-Campbell 345 flo Roosevelt-Tallmadge 345	TBD	TBD
	2928	LGEE	River Queen Tap-Earlington North 161	TBD	TBD
	2929	FE, DLCO	Sammis-Beaver Valley 345 flo Sammis-Highland 345	TBD	TBD
	2930	NIPS,AEP	Michigan City-Laporte Junction 138	TBD	TBD
	2931	FE, AEP	Sammis-S. Canton 345 flo Sammis-Star 345	TBD	TBD
	2932	FE, AEP	Sammis-S. Canton 345 flo Sammis-Wylie Ridge 345	TBD	TBD
	2934	FE, PJM	Sammis-Wylie Ridge 345 flo Tidd-Wylie Ridge 345	TBD	TBD
	2935	AEP, FE	S. Canton-Star 345 flo Sammis-Star 654.7	TBD	TBD
	2936	FE, PJM	Seneca-Krendale 138 flo Wylie Ridge-Cabot 500	TBD	TBD
	2937	FE	Seneca-Maple 138 flo Mansfield-Hoytdale 345	TBD	TBD
	2938	FE	Seneca-Maple 138 flo Wylie Ridge-Sammis 345	TBD	TBD
	2939	CIN, LGEE	Speed-Northside 138 flo Rockport-Jefferson 765	TBD	TBD
	2940	CIN	Speed 345/138 Xfm flo Rockport-Jefferson 765	TBD	TBD
	2943	FE	Star-Juniper 345 flo Star-Carlisle 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2944	MECS, IMO	St. Clair 345/230 Xfm T9 flo St. Clair-Lambton 345	TBD	TBD
	2946	HE	Taswell-Bedford 161 53.7	TBD	TBD
	2947	HE	TASWELL-RATTS 161KV	TBD	TBD
	2948	MECS	Thetford-Jewell 345 flo Hampton-Pontiac 345	TBD	TBD
	2949	LGEE	Tip Top-Cloverport 138 flo Baker-Broadford 765	TBD	TBD
	2950	MECS	Tompkins-Majestic 345 flo Oneida-Majestic 345	TBD	TBD
	2951	AEP, MECS	Twin Branch-Argenta 345 flo Cook-Benton Harbor 345	TBD	TBD
	2952	MECS	Whiting 138/120 Xfm flo Oneida-Majestic 345	TBD	TBD
	2953	MECS	Whiting 138/120 Xfmr flo Tompkins-Majestic 345	TBD	TBD
	2954	BREC, LGEE	Wilson-Green River 161	TBD	TBD
	2955	HE	Worthington-GPC 161	TBD	TBD
	2956	NIPS,AEP	Northport-Albion 138	TBD	TBD
	2957	CIN	Zimmer-Silver Grove 345 flo Zimmer-Port Union 345	TBD	TBD
	2958	HE, CIN	Merom-Dresser 345 (flo) Gibson-Petersburg 345	TBD	TBD
	2959	CIN	Cayuga-Nucor (flo) Wheatlan-Amo	TBD	TBD
	2960	CIN	Greentown 765/138 XFMR 1 (flo) Greentown 765/230/138 XFMR 2	TBD	TBD
	2961	CIN, HE	Worthington-Owen 138 (flo) Worhtington-Bloomington 345	TBD	TBD
	2962	CIN, AEP	Greentown 765/230/138 XFMR 2 (flo) Greentown-Dumont 765	TBD	TBD
	2963	LGEE, CIN	Ghent-Fairview 138 (flo) Ghent-Batesville 345	TBD	TBD
	2964	HE, CIN	Merom-Dresser 345 (flo) Merom-Worthington 345	TBD	TBD
	2965	CIN, HE	Gibson-Merom 345 (flo) Gibson-Petersburg 345	TBD	TBD
	2966	CIN	Bloomington-Columbus 230 (flo) Bedford-Columbus 345	TBD	TBD
	2967	CIN	Wabash River-Whitesville 230 (flo) Wabash River-Clinton 230	TBD	TBD
x	3001	CE,ALTE	WEMPLETOWN-PADDOCK 345 KV	MISO	MISO
	3002	ALTE	NELSON-DEWEY 161/138 XFMR	TBD	TBD
x	3003	ALTE	COLUMBIA-S. FOND DU LAC 345 KV	MISO	MISO
	3004	ALTE,MGE	COLUMBIA-N. MADISON 345 KV	TBD	TBD
	3005	ALTE,WPS	S. FOND DU LAC-FITZGERALD 345 KV	TBD	TBD
x	3006	ALTE,NSP,WEC,WPS	EAU CLAIRE-ARPIN 345 KV	MISO	MISO
	3007	WPS	ELLINWOOD-PROGRESS 138 KV	TBD	TBD
x	3009	NSP,ALTE,WEC,WPS	EAU CLAIRE-ARPIN+WEMPLETOWN-PADDOCK	MISO	MISO
	3010	ALTE	ROCKDALE 345/138 XFMR 1	TBD	TBD
x	3011	ALTE	PADDOCK 345/138 XFMR 1	MISO	MISO
x	3012	ALTE	PADDOCK XFMR 1 + PADDOCK-ROCKDALE	MISO	MISO
	3013	ALTE	ROCKDALE XFMR 1 + ROCKDALE XFMR 2	TBD	TBD
	3014	ALTE	ROCKDALE XFMR 2 + PADDOCK XFMR	TBD	TBD
	3015	ALTE	NELSON DEWEY XFMR+WMPLETOWN-PADDOCK	TBD	TBD
	3016	ALTE	NELSON DEWEY XFMR + ECL-ARP+Guide	TBD	TBD
	3017	ALTE,DPC	Cassvl-NED 161 for Wemp-Paddock 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3018	ALTE,WPS,WEC,NSP	EAU CLAIRE-ARPIN+PRAIRIE ISLAND-BYRON	MISO	MISO
	3020	ALTE	Rockdale Xfmr 1 for Paddock Xfmr	TBD	TBD
x	3021	ALTE	Paddock-Blackhawk 138 (flo) Paddock-Townline 138	MISO	MISO
	3022	ALTE	X59 Christiana-Kegonsa 138 for Columbia-N Madison 345	TBD	TBD
	3023	ALTE	ROE-Lkhd 138 for EauClair-Arp, Wien-Tcorners	TBD	TBD
x	3024	ALTE	Blackhwk-Colley Road 138 (flo) Paddock-Townline 138	MISO	MISO
x	3025	ALTE	Russel-Rockdale 138/Paddock-Rockda 154.1	MISO	MISO
	3026	ALTE	Rockdale TR2 for Rockdale TR 1	TBD	TBD
	3027	ALTE	Burlington-N Lk Geneva Tp flo Wempltown-Paddock	TBD	TBD
	3028	ALTE	Sand Lk-P Edwards 138 for N.Appl-Ror 345	TBD	TBD
	3029	ALTE	Green Lk-Roeder 138kV	TBD	TBD
	3030	ALTE	Green Lk-Roeder 138 for N Appleton-RoR 345	TBD	TBD
	3031	ALTE	X59 Christiana-Kegonsa 138 for F1 Christiana-Fitchburg 138	TBD	TBD
	3032	WPS	ROCKY RUN -NORTHPT+WESTON-ROCKY RUN	TBD	TBD
	3033	ALTE	Arpin Xformer+Arpin-Rocky Run 345	TBD	TBD
x	3034	ALTE	Blackhawk-ColleyRd xfmr FLO Paddock-Rockdale345	MISO	MISO
	3035	ALTE	Columbia-Portage138 FLO Columbia-Portage138 ckt2	TBD	TBD
	3036	ALTE	Columbia-Portage138 ckt2 FLO Columbia-Portage138	TBD	TBD
	3037	ALTE	Edgewater-S.SheboygnFls138 FLO Edgwtr-S.FndDuLac138	TBD	TBD
x	3038	ALTE	Paddock-Townline 138 (flo) Paddock-Blackhawk 138	MISO	MISO
	3039	ALTE	Rockdale 345-138 T1 FLO Rockdale 345-138 T3	TBD	TBD
	3040	ALTE	Rockdale 345-138 T2 FLO Rockdale 345-138 T3	TBD	TBD
	3041	ALTE, MGE	Columbia-N.Madison138 FLO Columbia-NMA345	TBD	TBD
	3042	ALTE	Townline-Janesville 138 (flo) Paddock-Rockdale 345	TBD	TBD
	3043	ALTE	Townline-Janesville 138 flo Townline-Tripp-Viking-Russell 138	TBD	TBD
	3044	ALTE	Townline-Janesville 138 flo Rockdale 345/138 Xfmr 3	TBD	TBD
x	3045	ALTE	Rockdale 345/138 Xfmr 3 flo Paddock 345/138 Xfmr	MISO	MISO
	3046	ALTE	Portage-Hamilton 138 flo Columbia-South Fond du Lac 345	TBD	TBD
	3047	ALTE	Arpin 345/138 Xfm flo Eau Claire-Arpin 345 + Op Guide	TBD	TBD
	3048	ALTE	Christiana-Kegonsa 138 flo N. Madison 345/138 Xfm #1 + Op Guide	TBD	TBD
	3049	ALTE	Columbia 345/138 Xfm #1 flo Columbia 345/138 Xfm #2	TBD	TBD
	3052	ALTE	Nelson Dewey 161/138 Xfm flo Arpin-Rocky Run 345 + Op Guide	TBD	TBD
	3053	ALTE	N. Madison 345/138 Xfm #1 flo N. Madison 345/138 Xfm #2 + Bus Tie	TBD	TBD
	3054	ALTE, WEC	Rockdale-Lakehead 138 flo Columbia-S. Fond du Lac 345	TBD	TBD
	3057	ALTE	T Corners-Wien 115 flo Arpin-Rocky Run 345 + Op Guide	TBD	TBD
	3058	ALTE	T Corners-Wien 115 flo Eau Claire-Arpin 345 + Op Guide	TBD	TBD
x	3059	CE, ALTE	Wempletown-Paddock 345 flo Arpin-Rocky Run 345 + Op Guide	MISO	MISO
x	3060	CE, ALTE	Wempletown-Paddock 345 flo King-Eau Claire-Arpin 345 + Op Guide	MISO	MISO

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3061	ALTE	Whitewater-Mukwonago 138 flo Paddock 345/138 Xfm	TBD	TBD
	3062	ALTE	Whitewater-Mukwonago 138 flo Paddock-Rockdale 345	TBD	TBD
x	3063	ALTE	Paddock-Townline 138 (flo) Paddock-Rockdale 345	MISO	MISO
	3102	AMRN,AECI	BLAND-FRANKS 345 KV	TBD	TBD
	3103	AMRN	CAHOKIA 345/138 XFMR 8	TBD	TBD
	3104	AMRN	CAHOKIA 345/138 XFMR 9	TBD	TBD
	3105	AMRN,EEI	JOPPA-CAPE GIRARDEAU 161 KV	TBD	TBD
	3106	AMRN	MASON 345/138 XFMR 2	TBD	TBD
x	3107	AMRN	MONTGOMERY-SPENCER 345 KV	MISO	MISO
	3108	AMRN,MPS	OVERTON-SIBLEY 345 KV	TBD	TBD
	3109	AMRN	RUSH ISLAND-ST FRANCOIS 345 KV	TBD	TBD
	3110	AMRN	QUINCY S-QUINCY E 138	TBD	TBD
	3111	IP,AMRN	XENIA -MT VERNON 345 KV	TBD	TBD
x	3112	AMRN,CILC	DUCK CREEK-IPAVA 345 kV	MISO	MISO
	3113	AMRN	NEWTON-CASEY 345 KV	TBD	TBD
x	3114	AMRN,AEP	BREED-CASEY 345 KV	MISO	MISO
x	3115	AMRN	COFFEEN-PANA 345 KV	MISO	MISO
	3116	AMRN	ALBION 345/138 XFMR	TBD	TBD
	3117	AMRN,AECI	Bland-Franks345 + Rush-St Francios + TR	TBD	TBD
	3118	AMRN	ALBION-XFMR + BREED-CASEY	TBD	TBD
x	3120	AMRN	COFFEEN-PANA+MONTGMRY-SPENCER	MISO	MISO
	3121	AMRN	ALBION XFMR + GIBSON-PETERSBURG	TBD	TBD
	3122	AMRN	ALBION XFMR + DUMONT-WILTON CENTER	TBD	TBD
x	3123	AMRN	COFFEEN-PANA+DUMONT-WILTON CENTER	MISO	MISO
	3124	AMRN,EEI	JOPPA-CAPE GIRARDEAU+SHAWNEE-KELSO	TBD	TBD
	3125	AMRN	SIDNEY-RANTOUL + SIDNEY-MIRA TAP	TBD	TBD
	3126	AMRN	SIDNEY-RANTOUL + COFFEEN-PANA-KINCAID	TBD	TBD
x	3127	AMRN	TAYLORVILLE-PAWNEE + COFFEEN-PANA-KINCAID	MISO	MISO
	3128	AMRN	S QUINCY-E QUINCY+QUINCY S-QUINC E	TBD	TBD
	3129	AMRN	MASON XFMR #3 + MASON XFMR #2	TBD	TBD
	3130	AMRN	ST FRANC XFMR+ST FRANC-LUTESVILLE	TBD	TBD
x	3131	AMRN	PAWNE-AUBURN+KINCAID-LATHM	MISO	MISO
	3132	AMRN	MURDOCK-SIDNEY + SIDNEY XFMR	TBD	TBD
	3133	AMRN	LABADIE-MASON3 + LABADIE-MASON4	TBD	TBD
	3134	AMRN	MISS TAP-ROXFRD1+MISS TAP ROXFRD 3	TBD	TBD
	3135	AMRN	ALBION-CROSSVL + XENIA-MT VERNON	TBD	TBD
	3138	AMRN	MONTGMRY-GUTHRIE+MONTGMRY MCCREDIE	TBD	TBD
x	3139	AMRN	PAWNEE WEST XFMR + PANA-KINCAID	MISO	MISO
x	3140	AMRN	MONTGMRY-SPENCER+COFFEEN-PANA-KINCAID	MISO	MISO

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3141	AMRN	MIS TAP3-ROXFRD + MIS TAP1-ROXFORD	TBD	TBD
x	3142	AMRN	RAMSEY-PANA + COFFEEN-PANA-KINCAID	MISO	MISO
	3143	AMRN	CAHOKIA XFMR 9 + CAHOKIA XFMR 8	TBD	TBD
	3144	AMRN	RUSH-ST FRANCOIS + BLANDS-FRANKS	TBD	TBD
x	3145	AMRN	PANA XFMR + COFFEEN-COFFEEN NORTH	MISO	MISO
	3146	AMRN,IP	MEREDOSIA-IND PARK+DUCK CRK-TAZEWL	TBD	TBD
	3147	AMRN,IP	MASON CTY-MT PLSKI FOR DUCK CRK-TAZEWL	TBD	TBD
	3148	AMRN	SIOUX-MISS TAP3+SIOUX-MISS TAP1	TBD	TBD
	3149	AMRN	SIOUX-MISS TAP3	TBD	TBD
	3150	AMRN	Newton 345/138 #2 for Newt-Casey345	TBD	TBD
	3152	AMRN	Meremac-St.Francois1Meremac-St.Francois2	TBD	TBD
	3153	AMRN	Clark Xfmr Bland-Franks	TBD	TBD
	3154	AMRN	Meremac-St.Francois Bland-Franks	TBD	TBD
	3157	AMRN	McCredie-Overton345 for Bland-Franks 345	TBD	TBD
x	3159	AMRN	Neoga-Holland-Ramsey 345 Bland-Franks 345	MISO	MISO
	3160	AECI,AMRN	Bland-Franks 345 for McCred-Overton 345	TBD	TBD
x	3161	AMRN, CWLP	Auburn-Chatham 138 flo Latham-Kincaid 345	MISO	MISO
	3162	SIPC,AMRN	Marion-S. Marion 161	TBD	TBD
	3163	SIPC, BREC	Renshaw-Livingston 161	TBD	TBD
	3164	SIPC,BREC	Renshaw-Livingston flo E. W Frankfort-Shawnee 345	TBD	TBD
	3165	SIPC,AMRN	S. Marion-Marion 161	TBD	TBD
x	3201	CE,AEP	11215 DUMONT-WILTON 765KV(AEP-CE)	PJM	PJM
x	3202	CE	17723 BURNHAM-TAYLOR 345KV	PJM	PJM
x	3203	CE	10802 LOCKPORT-LISLE 345 KV RED	PJM	PJM
x	3204	CE	10801 LOCKPORT-LISLE 345 KV BLUE	PJM	PJM
x	3205	CE	16703 PLANO- ELECT JCT 345 KV RED	PJM	PJM
x	3206	CE	16704 PLANO-ELECT JCT 345 KV BLUE	PJM	PJM
x	3207	CE	TSS116 GOODINGS GR 345KV RED BUSTIE	PJM	PJM
x	3208	CE	0621 BYRON-CHERRY VALLEY 345KV BLU	PJM	PJM
x	3209	CE	622 BYRON-CHERRY VALLEY 345KV RED	PJM	PJM
x	3210	CE	10802 Lock-LisR for 10801Lock-LiB+G	PJM	PJM
x	3211	CE	10801 Lock-LisB for 10802Lock-LiR+G	PJM	PJM
x	3212	CE	10802 Lock-Lisl R for 16703 PL-EJ R	PJM	PJM
x	3213	CE	10801 Lock-Lisl B for 16704 PL-EJ B	PJM	PJM
x	3214	CE	10322 Lis-LomR for 10321 Lis-LomB+G	PJM	PJM
x	3215	CE	10321 Lis-LomB for 10322 Lis-LomR+G	PJM	PJM
x	3216	CE	0621 Byron-ChV B for 0622 Byr-ChV R	PJM	PJM
x	3217	CE	0621 Byron-ChV B for 0624 Byr-Wemp	PJM	PJM
x	3218	CE	0622 Byron-ChV R for 0621 Byr-ChV B	PJM	PJM

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3219	CE	0622 Byr-ChV Red for 0624 Byr-Wemp	PJM	PJM
x	3220	CE	16704 Plan-EJ B for 16703 Plan-EJ R	PJM	PJM
x	3221	CE	16703 Plan-EJ Red for 16704 Pl-EJ B	PJM	PJM
x	3222	CE	11601 EFrk-GoodiB for 11602 EF-GG R	PJM	PJM
x	3223	CE	11602 EFrk-GoodiR for 11601 EF-GG B	PJM	PJM
x	3227	CE	0404 Quad-H471 for 15503 Cordo-Nelson	PJM	PJM
x	3228	CE	0403 Quad-Cord-Nelson for 0404 Quad-H471	PJM	PJM
x	3229	CE	11604 Goodi-LockR for 11617GG-LockB	PJM	PJM
x	3230	CE	11617 Goodi-LockB for 11604GG-LockR	PJM	PJM
x	3231	CE	GOODI 345R BT for 1223Dres-EJ B+T83	PJM	PJM
x	3232	CE	11120 EJ-W407 for 10802 Lock-LiR +	PJM	PJM
x	3233	CE	11124 EJ-Lomb for 10801 Lock-LiB +	PJM	PJM
x	3234	CE	2102 Kincaid-Lath for 11215 Dum-Wlt	PJM	PJM
x	3235	CE	2101 Kinc-BrokTp for 11215 Dum-Wilt	PJM	PJM
x	3236	CE,ALTE	17101 Wemp-Pad for 9922 Zion-Arcad	MISO	MISO
x	3237	CE,ALTE	17101 Wemp-Pad for 2221 Zion-PlsPr	MISO	MISO
x	3238	CE,ALTE	17101 Wemp-Pad for 15616 ChV-Silver	MISO	MISO
x	3239	CE,ALTE	17101 Wemp-Pad for Arpin-ÉauClar +G	MISO	MISO
x	3240	CE,WEC	2221 Zion-PlsPr for 9922 Zion-Arcd	PJM	PJM
x	3241	CE,WEC	2221 Zion-PlsP for 17101 Wemp-Pad	PJM	PJM
x	3242	CE,WEC	9922 Zion-Arcad for 2221 Zion-PlsP	PJM	PJM
	3243	CE,WEC	9922 Zion-Arcad for 17101 Wemp-Pad	TBD	TBD
x	3244	CE	Nels Tr84 for 15502 Nels-EJ +Tr82	PJM	PJM
x	3245	CE	15616 Cher-Silv for 15502 Nels-EJ	PJM	PJM
x	3248	CE	12204 Bel-Mar R for 15616 ChV-Silv	PJM	PJM
x	3249	CE	12205 Bel-Mar B for 15616 ChV-Silv	PJM	PJM
x	3250	CE	15502 Nels-EJ for 15616 Cher-Silv	PJM	PJM
x	3251	CE	0404 Quad Cities - NWS&W (H471)	PJM	PJM
x	3252	CE	11622 Elwd-GG R 345 for 1223 Dres-EJ R + Dres Tr 81	PJM	PJM
x	3253	CE	Kewanee(CE)-Kewanee(IP) 138 BT	PJM	PJM
x	3254	CE	Pwr JctB-Powerton 138	PJM	PJM
x	3257	CE,MEC	Quad City-SUB 91 345 KV	PJM	PJM
x	3258	CE,ALTW,MEC	Quad City-Rock Creek (FLO) QC-SUB91	PJM	PJM
x	3259	CE,MEC	Quad-SUB 91 345 for MEC Cordova-SUB 39(Moline) 345kV	PJM	PJM
x	3260	CE	15501 Lee Co-Nelson 345 for 17101 Wemp-Pad 345	PJM	PJM
x	3261	CE	L8012 Pontiac-Wiltn345 for L8014 Pont-Dresd345	PJM	PJM
x	3262	CE	Nelson 345-138 T82 for Nelson 345-138 T84	PJM	PJM
x	3263	CE	Nelson-Dixon B FLO Nelson-Nelson RT	PJM	PJM
x	3264	CE	Nelson-Nelson RT FLO Nelson-Dixon B	PJM	PJM

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3265	CE	OTDF ChV-Bel Red FLO ChV-SilvLk	PJM	PJM
x	3266	CE, ALTW	Garden Plain-Albany 138 flo Quad Cities-H471 345	PJM	PJM
x	3267	NIPS, CE	Munster-Burnham 345 flo Dumont-Wilton Center 765 + Op G	MISO	MISO
x	3268	NIPS, CE	Munster-Burnham 345 flo Dumont-Wilton Center 765	MISO	MISO
x	3269	NIPS, CE	Sheffield-Burnham 345 flo Dumont-Wilton Center 765	MISO	MISO
x	3270	CE, NIPS	State Line-Wolf Lake 138 flo Burnham-Sheffield 345	MISO	MISO
x	3271	CE, NIPS	State Line-Wolf Lake 138 flo Wilton Center-Dumont 765	MISO	MISO
x	3301	CILC	TAZEWELL - MASON 138 KV -50.0	MISO	MISO
x	3302	CILC	East Springfield-Holland 138 KV	MISO	MISO
x	3303	CILC,CWLP	E SPRINGFIELD-EASTDALE 138 KV	MISO	MISO
x	3304	CILC,CE	POWERTON-TAZEWELL 345 KV	MISO	MISO
x	3306	CILC	Holland-Mason138+Duck Creek-Tazewe 121.2	MISO	MISO
	3307	CWLP, CILC	Eastdale-E. Springfield 138 flo Kincaid-Latham-Pontiac	TBD	TBD
	3308	CILC	Holland-Mason 138 57.7	TBD	TBD
	3309	CILC	Kickapoo-Holland 138	TBD	TBD
x	3310	CE, CILC	Powerton-Tazewell 345 flo Powerton-Goodings Gr. 345 B	MISO	MISO
x	3311	CE, CILC	Powerton-Tazewell 345 flo Powerton-Goodings Gr. 345 R	MISO	MISO
	3350	SIPC	Renshaw-Livingston 161 for Kelso-Joppa 345	TBD	TBD
	3351	IP,SIPC	Campbell Hill-Campbell Hill Tap 138	TBD	TBD
x	3401	IP	SIDNEY XFMR + BUNSONVILLE XFMR	MISO	MISO
	3402	AMRN,IP	CAHOKIA-BALDWIN+COFFEEN-ROXFRD TAP	TBD	TBD
	3403	IP	SIDNEY-MIRA TAP + SIDNEY-SW CAMPUS	TBD	TBD
	3404	IP	STALLINGS XFMR+COFFEEN-ROXFORD TAP	TBD	TBD
x	3405	IP,AEP	BUNSONVILLE-EUGENE + BREED-CASEY	MISO	MISO
	3406	AMRN,IP	CAHOKIA-BALDWIN+STALLING-ROXFD TP	TBD	TBD
	3407	IP	STALLING XFMR + STALLINGS-ROXFORD	TBD	TBD
x	3408	IP	PANA-MOWEAQ T + KINCAID-LATHAM 146.7	MISO	MISO
	3409	IP	PANA-MOWEAQ T + PONTIAC-LATHAM	TBD	TBD
x	3410	IP	SIDNEY XFMR + DUMONT-WILTON	MISO	MISO
	3411	IP	SIDNEY-MIRA + SIDNEY-RANTOUL	TBD	TBD
	3412	IP	FAYET-TILDEN + BALDWN-MT VR345/138	TBD	TBD
x	3413	AMRN,IP	COFFN-ROXFD IP FOR XENIA-MT VRNON	MISO	MISO
x	3414	AMRN,IP	COFFN-ROXFD IP FOR COFFN-COFFN N	MISO	MISO
x	3416	IP	COFFEEN-ROXFORD 345	MISO	MISO
x	3418	IP	COFFEEN-ROXFORD 345 FOR LOSS OF BAKER-BROADFORD 765	MISO	MISO
x	3419	IP,AMRN	Xenia-MtVernon 345 for Coffeen-Roxfd 345	MISO	MISO
x	3420	IP	Coffeen-Roxford Rockport-Jefferson	MISO	MISO
	3421	AMRN	Rush Isl-St Francios 345 for Franks-Salem 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3422	AMRN	Rush Isl-St Francios345 for Wfrank-Mt Vern345	TBD	TBD
	3423	AMRN	Bland-Franks 345 for Lutes-Essx345,Kelso Guid	TBD	TBD
	3424	IP	Salem-W Mt Vernon Xenia-W MT Vernon	TBD	TBD
	3425	IP	Gillespie-Lacleed Tap 138 + Xenia-MtVern 345	TBD	TBD
	3426	IP	Baldwin-Cahokia 345 for Baldw-Stallings,Stal TR	TBD	TBD
	3427	SIPC,IP	Campbell Hill Tap-Campbell Hill 138	TBD	TBD
	3428	IP, MEC	Galesburg 161/138 Xfm #2 flo Elect	TBD	TBD
	3501	WEC	Whitewater-Mukwonago 138 flo King-Arpin 345 kV	TBD	TBD
	3502	WEC	OAK CREEK 345/230 XFMR	TBD	TBD
x	3503	WEC	ALBERS-PARIS 138 KV	MISO	MISO
	3504	WEC	PARIS-ST MARTINS 138 KV	TBD	TBD
	3505	WEC	FREDONIA-Cedarsauk 138 KV	TBD	TBD
	3506	WEC	ARCADIAN 345/138 XFMR	TBD	TBD
x	3507	ALTE,WEC	EDGEWATER-Cedarsauk-Granville 345 KV	MISO	MISO
	3508	WEC	BLUEMOUND-TOSA-W 138 KV	TBD	TBD
	3510	WEC	CONCORD-COONEY 138 KV	TBD	TBD
	3511	WEC	MUKWONAGO-ST MARTINS 138 KV	TBD	TBD
	3512	WEC	LS - WHITEWATER 138 KV	TBD	TBD
	3513	WEC	NLK GENEVA TAP-SUGAR CR 138 KV	TBD	TBD
	3514	WEC,UPPC	NORDIC-PERCH LAKE 138 KV	TBD	TBD
	3515	WEC	JEFFERSON-LAKEHEAD 138 KV	TBD	TBD
x	3517	WEC	ARCADIAN-GRANVILE 345 KV	MISO	MISO
	3518	WEC	BUTLER-GRANVILE+ARCADIAN-GRANVILE	TBD	TBD
	3519	WEC	BUTLER-GRANVILE+WEMPLETOWN-PADDOCK	TBD	TBD
	3520	WEC	Merril-Hil 138 for Wemp-Paddock 345	TBD	TBD
	3522	WEC	Albers-Paris138 for Wemp-Padock 345	TBD	TBD
	3523	WEC	Stiles-Pioneer 138 for N.Appl-WhiteClay138	TBD	TBD
	3524	WEC	Ellington-Hintz + N.Appleton-Rocky Run 345	TBD	TBD
	3525	WEC	Stiles-Amberg 138 for Morgan-Plains 345	TBD	TBD
	3526	WEC	Arcadian TR 345-138 for Arcad-Gran	TBD	TBD
x	3527	WEC	PleasPr-Racine 345 for Wemp-Pad 345	MISO	MISO
	3528	WEC	N Appleton-Wh Clay 138 for Stiles-Pulliam 138 #64451	TBD	TBD
x	3529	WEC,WPS	N. Appleton-Rocky Run 345kV	MISO	MISO
	3530	WEC	Jeffrsn-LakehdCam138 Col-SFL345	TBD	TBD
	3531	WEC	WhtWater-Mukwanago138 Roe-Jeff138	TBD	TBD
	3532	WEC	Ellington-Hintz 138 for N.Appleton-Rocky Run 345	TBD	TBD
	3533	WEC	Whitewater-Mukwonago 138 for SFL-Columbia 345	TBD	TBD
x	3534	WEC	Kenosha-Albers 138 for Wempletown-Paddock 345	MISO	MISO
	3535	WEC	N.Appleton-LostDauphin 138 for Kewaunee 345-138 TR	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3536	WEC	N.Appleton 345/138 T1 for N.Appleton 345/138 T3	TBD	TBD
x	3537	WEC	Kenosha-Lakeview 138 for PleasPr-Zion 345	MISO	MISO
	3538	WEC,WPS	Pulliam4-Stiles 138 (flo) Pulliam5-Stiles 138	TBD	TBD
	3539	WEC	VALLEY-HAYMKT 138+GRANVL1-ARCADN1 345	TBD	TBD
	3540	WEC	VALLEY-HAYMKT 138+BLUMND3-OC CRK7 230	TBD	TBD
	3541	WEC	VALLEY-HAYMKT 138+BLUMND5-OCONNR-6 138	TBD	TBD
	3542	WEC	Amberg-Plains 138 flo Morgan-Plains 345	TBD	TBD
	3543	WEC	Granville-Swan 138 flo Saukville 345/138 Tr 1	TBD	TBD
	3544	WEC	Stiles-Amberg 138 & Stiles-Crivitz 138 flo Morgan-Plains 345	TBD	TBD
	3545	WEC	Amberg-Plains138 FLO Now Tap-Amberg138	TBD	TBD
	3546	UPPC, WEC	Cedar-National138 FLO Cedar-Tilden138	TBD	TBD
	3547	WEC	Granville 345-138 Xfr FLO Wempletown-Paddock345	TBD	TBD
	3548	WEC	Lakehead-Haiwatha 138kV 32.9	TBD	TBD
	3549	WEC	N.Appleton-LostDauphin138 (flo) Kewaunee-East Krok 138	TBD	TBD
	3550	WEC	N.Appleton-WhiteClay138 FLO Stiles-Pulliam138	TBD	TBD
	3551	WEC	N.Appleton 345-138 T1 FLO N.Appleton 345-138 T2	TBD	TBD
	3552	WEC	N.Appleton 345-138 T2 FLO N.Appleton 345-138 T1	TBD	TBD
	3553	WEC	N.Appleton 345-138 T2 FLO N.Appleton 345-138 T3	TBD	TBD
	3554	WEC	N.Appleton 345-138 T3 FLO N.Appleton 345-138 T2	TBD	TBD
	3555	WEC	Plains-Amberg138 FLO Now Tap-Amberg138	TBD	TBD
	3556	WEC	Plains-Amberg138 FLO Morgan-Plains345	TBD	TBD
x	3557	WEC	PleasPrairie-Arcadian138 FLO PleasPrairie-Racine345	MISO	MISO
x	3558	WEC	PleasPrairie-Arcadian345 FLO Zion-Arcanian345	MISO	MISO
	3559	WEC	Stiles-Crivitz115 FLO Morgan-Plains345	TBD	TBD
x	3560	WEC	Whitewater-Mukwonago FLO CherryVal-SilvrLk345	MISO	MISO
	3561	WEC	Whitewater-Mukwonago138 FLO Univer 93.6	TBD	TBD
	3562	WEC,MECS	McGulpin-Straits138 ckt. 3 FLO ckt. 1	TBD	TBD
	3563	WEC, WPS	N.Appleton-LostDauphin138 FLO N.Appleton-Mason St138	TBD	TBD
	3564	WEC,MECS	McGulpin-Straits138 ckt. 1 FLO ckt. 3	TBD	TBD
	3565	WEC	Paris-Burlington 138 (flo) Wempletown-Paddock 345	TBD	TBD
	3566	WEC	N Appleton-Wh Clay 138 flo Stiles-Pulliam 138 #64441	TBD	TBD
	3567	WEC	Flow South	TBD	TBD
	3568	WEC	Amberg-Stiles 138 flo Plains-Morgan 345	TBD	TBD
	3569	WEC	ATC Flow North	TBD	TBD
x	3570	WEC, CE	Pleasant Prairie-Zion 345 flo Cher 125.7	PJM	PJM
x	3571	WEC, CE	Pleasant Prairie-Zion 345 flo Zion-Arcadian 345	PJM	PJM
x	3572	WEC, CE	Pleasant Prairie-Zion 345 flo Zion-Arcadian 345 + Op Guide	PJM	PJM
	3573	WEC, MECS	Straits-McGulpin 138 #1 flo Straits-McGulpin 138 #3	TBD	TBD
	3574	WEC, MECS	Straits-McGulpin 138 #3 flo Straits-McGulpin 138 #1	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3575	WEC	Center-Fiebrantz 138 flo Arcadian- 113.8	TBD	TBD
	3576	WEC	Center-Fiebrantz 138 flo Wempletow 95.7	TBD	TBD
	3577	WEC	Center-Fiebrantz 138 (flo) Arcadia 172.0	TBD	TBD
	3578	WEC	Albers-Paris 138 (flo) Pleasant Prairie-Racine 345	TBD	TBD
	3579	WEC	Stiles-Pioneer 138 (flo) White Clay-Morgan 138	TBD	TBD
	3580	WEC,WPS	White Clay - Morgan 345kV (flo) Stiles - Pulliam 138kV	TBD	TBD
	3581	WEC	Stiles - Pulliam 138kV (flo) White 117.4	TBD	TBD
x	3601	ALTE,WPS	ARPIN - ROCKY RUN 345 KV	MISO	MISO
x	3602	WPS,WEC	ROCKY RUN - N APPLETON 345 KV	MISO	MISO
x	3604	WPS,ALTE	N FOND DU LAC-AVIATION 138 KV	MISO	MISO
	3605	WPS,WEC	MASON ST - N APPLETON 138 KV	TBD	TBD
	3606	WPS,WEC	HIGHWAYV - ROCKLAND 138 KV	TBD	TBD
	3607	WPS	HIGHWAYV - PREBLE 138 KV	TBD	TBD
	3608	WPS	WHITING AVE. - HOOVER 115 KV	TBD	TBD
	3609	WPS	ROCKY RUN-WESTON 345 KV	TBD	TBD
	3611	WPS	KEWAUNEE 345/138 XFMR	TBD	TBD
	3612	WEC,WPS	N APPLETON-FITZGERALD 345KV	TBD	TBD
	3613	WPS	KEWAUNEE XFMR+KEWAUNEE-N APPLETON	TBD	TBD
	3614	WPS	ROCKY RUN-WHITING AVE 115KV	TBD	TBD
	3615	WPS	ROCKY RUN-NORTHPT 115KV	TBD	TBD
	3616	WPS	WESTON-KELLY 115KV	TBD	TBD
	3617	WPS	HIGHWAYV-PREBLE+N APPLTN-WHITE CLAY	TBD	TBD
	3618	WPS	HIGHWAYV-PREBLE+N APPLTN-MASON ST	TBD	TBD
	3619	WPS	Kewaunee 345/138 for PtBeach-N.Appleton 345	TBD	TBD
	3620	WPS	RockyRun-Whiting115 FLO N.Appleton-RockyRun345	TBD	TBD
	3621	WPS	Whiting-Hoover115 FLO N.Appleton-RockyRun345	TBD	TBD
	3622	WPS	Weston 345-115 T1 FLO RockyRun 345-115 T1	TBD	TBD
	3623	WPS, WEC	Kewaunee-N.Appleton xfmr FLO N.Appleton-PtBeach345	TBD	TBD
	3624	WPS, WEC	Kewaunee-PtBeach345 FLO N.Appleton-PtBeach345	TBD	TBD
	3625	WPS, ALTE	Cranberry Loop 115kV	TBD	TBD
	3626	WPS	Lost Dauphin-Red Maple 138 flo Kewaunee-East Krok 138	TBD	TBD
	3627	WPS	Depere-Glory Rd 138 flo Kewaunee-E.Krok 138	TBD	TBD
	3628	WPS	Neevin-Butte de Morte 138kV FLO Fitzgerald 345/138 xfmr	TBD	TBD
	3629	WPS	N. Fond du Lac-Aviation 138kV FLO Fitzgerald 345/138 xfmr	TBD	TBD
	3630	WPS	Rocky Run-Weston 115 flo Rocky Run-Weston 345	TBD	TBD
	3631	WPS	Highway V - Preble 138 (flo) Lost Dauphin - Red Maple 138	TBD	TBD
	3701	ALTW	Poweshiek-Reasnor 161 kV	TBD	TBD
	3702	ALTW	Poweshiek-Reasnor 161 flo Arnold-Hazleton 345	TBD	TBD
	3703	ALTW	Poweshiek-Reasnor161 for Arnold-Tifften	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
Under Discussion	3704	ALTW	Poweshiek-Reasnor 161 for Montezuma-Bondurant 345	TBD	TBD
x	3705	ALTW	Arnold-Hazelton 345 for Wemp-Paddock 345	MISO	MISO
x	3706	ALTW	Arnold - Hazleton	MISO	MISO
	3707	ALTW	Lore-Turkey River 161 (flo) Wempletown-Paddock 345	TBD	TBD
	3708	#N/A	Adams 345/161kV TR9	TBD	TBD
	3710	#N/A	Adams 345-161 for Adams-Hazleton 345	TBD	TBD
x	3711	ALTW	Albany 161-138 for Nelson-Cordo B 345	MISO	MISO
	3713	ALTW	Lakefield 345-161 for Byron-Adams 345	TBD	TBD
	3714	ALTW	Lakefield Jct.-Fox Lk 161 for Arnold-Hazelton 345	TBD	TBD
x	3715	ALTW,CE	Quad Cities-Rock Creek 345/MEC Cordova-Sub 39	PJM	PJM
x	3716	ALTW	Rock Creek 345/161 TR for Quad-Sub 91 345	MISO	MISO
	3717	ALTW	Rock Creek-Dewitt 161 Quad Cities-Sub91 345	TBD	TBD
	3718	ALTW	RockCreek-Dewitt 161 for meccord3-sub39 345kV	TBD	TBD
x	3719	ALTW	Salem 345/161 Quad Cities-Sub 91	MISO	MISO
x	3720	ALTW	Salem 345/161 TR for MEC Cordova-Sub 39 345kV	MISO	MISO
x	3721	ALTW	Salem 345/161 for Quad-Sub 91 TR	MISO	MISO
x	3723	ALTW	Tiffon-D.Arnold 345 for Hills-Montezuma 345kV	MISO	MISO
	3724	ALTW	Arnold-Vinton 161 for D.Arnold-Hazleton 345	TBD	TBD
	3725	ALTW	Sub 56(Davnprt)-E.Calamus161 for Q 141.3	TBD	TBD
	3726	ALTW	Ames-BooneJct 115 for Montezuma-Bo 6.7	TBD	TBD
	3727	ALTW	Lakefield-Fox Lk 161 for Lakefield-LGS 345	TBD	TBD
	3728	ALTW	Dysart-Washburn 161 for D.Arnold-Hazleton 345	TBD	TBD
	3730	ALTW	Bondurant-BooneJct 161 for Lehigh- 106.3	TBD	TBD
	3731	ALTW	Lakefield Jct.-Fox Lake 161 flo Lakefield Jct.-Triboji 161	TBD	TBD
x	3732	ALTW	Arnold-Hazelton 345 (flo) Dorsey-Forbes 500	MISO	MISO
	3733	ALTW	Hazleton-Dundee 161 Eau Claire-Arpin 345	TBD	TBD
	3734	ALTW	E.Calamus-Calamus 115 for Arnold-Tiffin 345	TBD	TBD
	3735	ALTW,WAUE	Wisdom-Triboji 161 flo Raun-Lakefield 345	TBD	TBD
x	3736	ALTW	Salem 345/161 flo Wempletown-Paddock 345	MISO	MISO
	3737	ALTW	Hills 345/161 Xfmr flo Tiffin-Duane Arnold 345	TBD	TBD
	3738	ALTW	8th St-Lore 161 flo Wempletown-Paddock 345	TBD	TBD
	3739	ALTW	8th St.-Lore 161 flo Arnold-Hazleton 345	TBD	TBD
x	3740	ALTW,CE	Albany-Garden Plain 138 flo Quad Cities-H471 345	PJM	PJM
	3741	ALTW	Marshalltown-Fernald 115 (flo) Mon 52.7	TBD	TBD
	3742	ALTW	Lime Creek-Emery 161 flo Lehigh-Webster 345	TBD	TBD
	3743	ALTW	Lore-Turkey River 161 flo Wempletown-Paddock 345 + Op Guide (Summer-only)	TBD	TBD
	3744	ALTW	Vinton-Dysart 161 flo Arnold-Hazleton 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3745	ALTW	Lime Creek-Emery 161 flo Adams-Hazleton 345	TBD	TBD
	3746	ALTW	Salem-Julian Center 161 (flo) Wempletown-Paddock 345	TBD	TBD
	3747	ALTW	Lakefield-Fox lake 161 (flo) Lakefield-Wilmarth 345	TBD	TBD
	3748	ALTW,MEC	Reasnor 161-Des Moines (flo) Monte 93.5	TBD	TBD
x	3749	ALTW	Arnold-Hazelton 345 (flo) Montezuma-Bondurant 345	MISO	MISO
	5008	CSWS	CraAshValLyd	TBD	TBD
	5014	CSWS	ElkXfrTucOku	TBD	TBD
	5017	OKGE	FTSXFR500345	TBD	TBD
	5021	OKGE,WR	KilCreWooWic	TBD	TBD
	5022	KCPL,WR	LacNeoLanWic	TBD	TBD
	5023	KCPL	LacStiLacWgr	TBD	TBD
	5035	KCPL,AECI	MontroClintn	TBD	TBD
	5037	OKGE,CSWS	MusClaMusRss	TBD	TBD
	5050	MPS,KCPL	StjLaklatStr	TBD	TBD
	5051	SPA,AECI	StockMorgan	TBD	TBD
	5052	SPA,AECI	StoMorLacNeo	TBD	TBD
	5053	SPA,AECI	StoMorMorBrk	TBD	TBD
	5063	CSWS	NesOneNesTul	TBD	TBD
	5076	OKGE	FtSmthANOVlt	TBD	TBD
	5077	OKGE,WR	CreKilWicWoo	TBD	TBD
	5085	CSWS	DanMagAnoFts	TBD	TBD
	5090	CLEC,CSWS,EES	DolXfrEldXfr	TBD	TBD
	5099	CSWS,OKGE	PitSemPitSun	TBD	TBD
	5100	SPS	PriSpePriSpe	TBD	TBD
	5194	OKGE	FTSXFR345161	TBD	TBD
	5196	SPS	SPS North - South	TBD	TBD
	5200	KCPL	LacWgrLacSti	TBD	TBD
	5204	WR	SphWmcSumEmc	TBD	TBD
	5207	OKGE	RedArcRedArc	TBD	TBD
	5214	OKGE	WdrCimSprNrw	TBD	TBD
	5215	CSWS	ValLydEldLon	TBD	TBD
	6001	WAUE,OTP,NSP,MP	NDEX	TBD	TBD
	6002	MHEB,WAUE,NSP	MHEX_S	TBD	TBD
	6003	WAUE,MHEB,NSP	MHEX_N	TBD	TBD
	6004	ALTE,WEC,WPS,NSP	MWSI	TBD	TBD
	6006	NPPD	GGS	TBD	TBD
	6007	NPPD	GENTLMN3 345 REDWILO3 345 1	TBD	TBD
	6008	NPPD	GRIS_LNC	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	6009	NPPD,MPS,AECI,OPPD	COOPER_S	MAPP	MISO
	6012	NSP,SMP	PRI-BYN	TBD	TBD
	6013	NSP	LKM-WFB	TBD	TBD
	6014	OPPD	FTCAL_S	TBD	TBD
	6015	DPC,NSP	ROCHSTR-ALMA / KING-ECL	TBD	TBD
	6017	SMP,ALTW	LAKEFIELD XFMR / BYRON-ADAMS	TBD	TBD
	6018	OTP,WAUE	CENTER - HESKETT 230	TBD	TBD
	6019	OTP	CENTER - JAMESTOWN 345	TBD	TBD
	6021	NPPD	ENDERS-BEVERLY / GENTL-REDWIL	TBD	TBD
	6022	NPPD	GRISLD-YORK / GRISLD-MCCOOL	TBD	TBD
	6023	NPPD	N.PLATTE-STVL /GENTL-REDWIL	TBD	TBD
	6024	NPPD	RED WILLOW - MINGO	TBD	TBD
	6026	WAUE	JMSTN-FARGO 1 AND JMSTN-FARGO 2	TBD	TBD
	6029	NSP,SMP	ROCHESTER-SILVER LAKE/PRI-BYRON	TBD	TBD
	6030	NPPD,OPPD	Nebraska City-Cooper 345kV	TBD	TBD
	6031	NPPD	GrandIsl-Aurora-Pauline-MarkMoore345kV	TBD	TBD
	6034	MEC,NPPD	RAUN-TEKAMAH 161KV	TBD	TBD
	6056	OTP,WAUE	JMS-PIC JMS-FARGO 1&2 FLO CEN-JMS]	TBD	TBD
	6057	MEC	Sub T-Hills 345kV FLO Sub 93-Sub 92 345kV	TBD	TBD
	6059	NSP,SMP	Silver Lake-Rochester 161kV FLO Byron-Pleasant Valley 345kV	TBD	TBD
	6060	MHEB,NSP	D602F 500KV	TBD	TBD
	6061	MHEB,NSP	R50M 230KV	TBD	TBD
	6062	SMP,NSP	Cascade Creek - Crosstown 161 (flo) King - Eau Claire	TBD	TBD
	6069	DPC,NSP	Alma - Wabaco 161kV (flo) Eau Claire - Arpin 345kV	TBD	TBD
	6072	MHEB	L20D 230kV	TBD	TBD
	6073	MEC,WAUE	Morningside-Plymouth 161kV FLO Raun-Sioux City 345kV	TBD	TBD
x	6074	MEC	Sub 91 345/161kV XFMR FLO Sub 91-Sub 56 345kV	MAPP	MISO
x	6081	MEC	Quad City West 345kV	MAPP	MISO
	6082	#N/A	SUB 92-HILLS FOR LOSS OF LOUISA_SUB T	TBD	TBD
	6083	NSP,SMP	Cascade Creek-Crosstown 161kV FLO Byron - Pleasant Valley 345kV	TBD	TBD
x	6084	MEC	East Moline 345/161 XFMER (flo) Quad Citites - Sub 91	MAPP	MISO
	6085	DPC	Genoa-Coulee FLO Genoa-LaCrosse-Marshland 161kV	TBD	TBD
x	6086	MEC	Montezuma-Bondurant 345kV	MAPP	MISO
	6087	NSP,SMP	Cascade Creek-Crosstown 161kV flo Adams Tramsformer 345/161kV	TBD	TBD
x	6088	DPC,NSP	Genoa-Seneca (flo) Eau Claire-Arpin	MAPP	MISO
	6089	NSP,SMP	Cascade Creek - IBM FLO Byron - Adams	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	6102	MPS	St. Joe - Midway 161kV 88.8	TBD	TBD
	6104	MPS	Iatan - St. Joe 345kV	TBD	TBD
x	6105	ALTW,CE	Quad Cities - Rock Creek	PJM	PJM
	6108	ALTW, DPC	TURKEY RVR-CASSVILLE FLO WEMP-PADDOCK	TBD	TBD
	6110	GREN	McHenry-Ramsey 230 FLO Center-Jamestown 345kV	TBD	TBD
	6111	NPPD,WAUE	GRAND ISLAND XFMR FLO GRAND ISLAND	TBD	TBD
	6112	SMP	Byron-Maple Leaf 161 flo Byron-Pleasant Valley 345	TBD	TBD
	6113	SMP	Byron-Maple Leaf 161 flo Pleasant Valley-Adams 345	TBD	TBD
	6114	DPC	Wabaco-Alma 161 flo Prairie Island-Byron 345	TBD	TBD
	6115	MPS	St. Joe-Midway 161kV flo St. Joe-F 103.5	TBD	TBD
	6116	DPC	Alma-Elk Mound 161 kV flo King-Eau Claire 345kV	TBD	TBD
x	6117	MEC	Sub 92-Hills flo Sub 93-Sub T-Hills	MAPP	MISO
	6118	MEC	Sub 93-Sub 31T flo Quad-Rock Ck 345	TBD	TBD
	6119	NSP	Adams 345/161 Xfmr flo King-Eau Claire Arpin 345	TBD	TBD
	6120	MHEB,WAUE	Glenboro - Rugby 230 kV	TBD	TBD
	6122	MEC	Council Bluffs-Avoca 161kV flo Council Bluffs-Madison County 345kV	TBD	TBD
	6123	MEC	Raun-Sioux City 345kV flo Raun-Lakefield 345kV	TBD	TBD
x	6124	MEC,ALTW	Sub K/Tiffin-Arnold 345kV	MAPP	MISO
	6125	MEC,OPPD	S1226-Tekamah 161kV flo Neal Gener	TBD	TBD
	6126	MEC,OPPD	S1226-Tekamah 161kV flo S3451-Raun 345kV	TBD	TBD
	6127	LES,OPPD	Sub 1214-70th & Bluff 161kV flo Cooper-Nebraska City 345kV	TBD	TBD
	6128	MEC,WAUE	Morningside-Plymouth 161kV flo Raun-Sioux City 345kV	TBD	TBD
	6129	MHEB,NSP,MP	Forbes-Chisago 500kV	TBD	TBD
	6130	NSP,WAUE	Granite Falls-Minnesota Valley 230kV	TBD	TBD
	6131	NSP	King-Eau Claire 345kV	TBD	TBD
	6132	NSP,SMP	Prairie Island-Red Rock #2 345kV flo Prairie Island-Byron 345kV	TBD	TBD
x	6136	CE, MEC	Quad Cities-Sub 91 345 flo Quad Cities-Rock Creek 345	PJM	PJM
	6137	ALTW, DPC	Turkey River-Cassville 161 flo Wempletown-Paddock 345 + Op Guide (Summer-only)	TBD	TBD
	6138	MHEB,WAUE	Glenboro - Rugby North 230kV	TBD	TBD
	6139	WPEK	Judson Large-Greensburg 115kV (flo) Spearville-Mullergren 230kV	TBD	TBD
	6140	WPEK	Medicine Lodge Transformer 138/115	TBD	TBD
	6141	WPEK	Sun City-Medicine Lodge 115	TBD	TBD
	6143	WAUE	Leland Olds KV2A 345/230 for Leland Olds KV1A 345/230	TBD	TBD
	6144	NSP,ALTW	Lakefield - Lakefield Gen 345kV	TBD	TBD
	6145	MPS	Lake Road-Nashua 161 flo Iatan-Stranger Creek 345kV	TBD	TBD
	6146	MEC,NPPD,OPPD	Tekamah-Raun 161kV flo Sub 3451-Raun 345kV	TBD	TBD
	6147	OPPD	Sub 3451-Raun 345kV	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	7004	NYIS	CENTRAL - CAPITAL	TBD	TBD
	7101	IMO	BLIP-(Buchanan Longwood Input)	TBD	TBD
	7102	IMO	QFW-(Queenston Flow West)	TBD	TBD
	7104	IMO	NEGATIVE_BLIP(Negative Buch Lgwd Input)	TBD	TBD
	11883	#N/A	Miami Fort 345/138 Xfmr 9 (flo) Zimmer Unit 1	TBD	TBD
	2969	#N/A	Miami Fort 345/138 Xfmr 9 (flo) Jefferson-Hanging Rock 765	TBD	TBD
	2970	#N/A	Miami Fort 345/138 Xfmr 9 (flo) Rockport-Jefferson 765	TBD	TBD
	2971	#N/A	Smith-Hardin Co 345 (flo) Ghent-West Lexington 345	TBD	TBD
	2972	#N/A	Newtonville-Cloverport 138 (flo) Wilson-Green River 161	TBD	TBD
	6148	#N/A	Genoa-LaCrosse-Marshland flo Genoa-Coulee	TBD	TBD
	6149	#N/A	Raun-Sioux City 345KV	TBD	TBD

Appendix G- Issues and Resolutions

The table on the following pages contains a comprehensive list of issues and questions that were identified from the following sources:

- MISO/PJM/SPP website comments
- MISO/PJM Seams Stakeholders meetings
- NERC OC Meetings
- NERC MISO/PJM Review Team Meetings
- Regional Meetings

The table attempts to list each issue that has been raised, and direct the reader to the documentation where the issue is addressed – or explain why it was not.

ISSUE	DOCUMENTATION/COMMENTS
1. Parallel Flows	
1.1. Congestion Management Procedures	
1.1.1. Why are Market Flows being split into only priorities 6 and 7 of the NERC curtailment priorities.	-All Market Flows within PJM and MISO would be are under their single, respective tariffs – and therefore candidates for Priority 6, network service or Priority 7, Firm. However, the proposal was enhanced to Prioritize flows committed same day to be Priority 2, non-firm hourly for those Flowgates where owners agreed to a reciprocal coordination agreement.
1.1.2. Define steps that will be taken (redispatch first, TLR non-firm second, TLR firm third etcetera) for PJM, MISO, and 3rd party Flowgates.	-This is covered in new section "Process to Respect Flowgate Capabilities"
1.1.3. Tagging in, out, or across markets – are MW impacts properly accounted for?	Interchange transactions are tagged back to marginal units per proposal to provide better granularity than today.
1.1.4. Do Market Flows include transactions in, out, or across market or only all Control Zones NNL plus inter Control Zone flows?	- Market Flows include all flows caused by generators in the market that are not tagged and provided to NERC IDC. Grand-fathered internal transactions are tagged and interchange transactions in, out or across the market will be tagged.
1.1.5. IDC modeling vs LMP modeling of Flowgate impacts	- This proposal provides the mechanism to quantify, prioritize, and marry LMP market impacts on Flowgates to the Tariff priorities in the IDC. The real-time modeling provided by the LMP systems will greatly enhance overall granularity of the IDC.

ISSUE	DOCUMENTATION/COMMENTS
1.1.6. Creation of Flowgates on the fly.	-"Process to Develop Flowgates on the Fly" is provided in this document.
1.1.7. Communications of curtailments back to RCs	-Communication of curtailments through same channels as used today – NERC IDC.
1.1.8. Are generators that are within PJM but not part of the market included in calculating the "Market Flows"?	- Yes, all flows caused by generators in the market will be included in the market flow calculation. The market flow calculation is adjusted for tagged flows so double counting doesn't occur.
1.1.9. Multiple relief requests, how calculated?	- Once it is determined relief is needed on a Flowgate and that TLR will be used, the Multiple relief requests will be handled sequentially as it is today in the IDC.
1.1.10. Explain calculation of Market Flows	-"Defining Monitored Flows" this document
1.1.11. Market Flow Calculation engine:	-RTO State Estimator/LMP engine will be used for accuracy.
1.1.11.1. LMP (pros/cons?)	- Robust, real time, and well maintained model that is also used to set LMP prices. Granularity down to the real time output of generators and actual load will provide greater accuracy. RTOs need ability to quantify flows/impacts outside IDC to enable RTO to RTO, Market to Market congestion management outside IDC to achieve greater efficiencies without calling TLRs.
1.1.11.2. NERC IDC (pros/cons?)	- Less accurate without major enhancements. Duplicative with RTO requirements for models needed to run markets.
1.1.11.3. Industry oversight of calculations – IDCWG or DFWG? Auditable, repeatable, verifiable calculations?	- RTOs will provide mechanism for NERC to audit calculations. See Appendix K.
1.1.11.4. Synchronicity of models	- Achieved through use of real time ICCP/ISN data for observable areas of market and with SDX data for outlying areas.
1.1.12. Why isn't the real-time shift of generation under market operations (or more specifically the difference between the day-ahead market dispatch and the real-time dispatch) not being treated similar to non-firm redirects in the hourly market.	- Will be considered non-firm hourly priority with parties willing to reciprocate actions
1.1.13. NNL Calculation:	-"Calculation of NNL" this document
1.1.13.1. Real time – for real time, will PJM be getting 5 second scans? Every 6 minutes? What is the scan-rate?	- Will provide Market Flows to IDC at least every 15 minutes (as requested by OATI and the IDCWG, the RTOs could provide updates as often as every 5 minutes..

ISSUE	DOCUMENTATION/COMMENTS
1.1.13.2. Will the market flow methodology be used to determine the market flow impact on all Flowgates? Will MISO use the same methodology once their market is up? If not, what is the guarantee that comparability will be achieved?	- Will be used for all Coordinated Flowgates as defined in paper. MISO and PJM will use same methods when MISO's market starts and PJM expands.
1.1.13.3. In your (PJM's) realtime model, you are going to run sensitivity studies. How far do your model(s) go out? Are they robust enough to capture flows/impacts in Michigan? Wisconsin? Missouri?	- In order to model the Coordinated Flowgates, PJM EMS model will grow from a 7,000 bus model to a 24,000 bus model. As such, PJM is very confident that its model will be more than robust enough to capture all of its flows on each of the Coordinated Flowgates it impacts.
1.1.13.4. Display "timeline" of this process.	- See examples.
1.1.13.5. How to calculate NNL service for new network resources (e.g., generators)	- MISO and PJM will use existing processes to designate new network resources.
1.1.14. Tagging Issues and Solutions:	
1.1.14.1. Would the IDC ignore those transactions/tags in, out, and through PJM regarding the market coordination Flowgates as they relate to calculating distribution factors and/or impacts in lieu of the values submitted by PJM	-All tag impacts will be calculated/ represented by the IDC just as they are today – regardless of whether viewing a coordination Flowgate or other Flowgate. MISO and PJM will, however, provide better information to IDC as to the source or sink of those transactions.
1.1.14.2. If using the marginal generator to calculate the distribution factors, how would the IDC be aware of the marginal generator?	-Marginal units within PJM and MISO will be communicated to IDC in the form of generation participation factors
1.1.14.3. Why would it be advantageous for the RTO to calculate TDFs vs the IDC?	- This concept was is earlier draft proposal and is no longer being pursued Additionally, both the NERC MISO/PJM Review Team and NERC OC endorsed the concept of the RTOs making these calculations.

ISSUE	DOCUMENTATION/COMMENTS
1.1.14.4. How determined what of Market Flow impacts will be considered 6NN and what will be considered 7-F	See Sections 5 and 6.
1.1.14.5. How to avoid double-counting Firm pt-pt schedules	- Process provides method so "partial path reservations" are not double counted.
1.1.14.6. How will you synchronize timing of MISO and PJM flow calculations (every five minutes) with the IDC calculations?	- Calculations will be performed at least every 15 minutes at an agreed upon time.
1.2. ATC/AFC Coordination	
1.2.1. AFC calculation and consideration of external Flowgates	- MISO and PJM are offering to coordinate AFC/ATC calculations with any external parties wishing to do so. As per the Appendix on MISO/PJM AFC Coordination, the RTOs will each be respecting over 300 Flowgates external to their respective boundaries.
1.2.2. If your firm AFC calculations are based on day-ahead, how firm is day-ahead? If it is not extremely accurate, PJM's firm Allocation could be taking up room on a Flowgate, while in reality the total MWs flowing current day may only be a fraction of the Allocation that was calculated day-ahead. This could result in keeping people off of Flowgates when there is in fact room on the Flowgate. And currently this could be done for free, because the PJM customer would not have to pay for it unless they used it.	AFC and NNL calculations will allocate firm room on Flowgates in advance to those parties participating in the reciprocal agreements to coordination firm/NNL on those Flowgates. Any unused Flowgate capabilities are released for non-firm near real time.
1.2.3. If there is any capacity left after MISO and PJM have made a determination, what is timeframe for making use of this capacity?	- Non-firm, Priority 6 is made available on a day-head basis and non-firm hourly is made for current day.
1.2.4. Define transmission Allocation/ entitlement	- Process to account for firm and no-firm commitments on Flowgates to help present over subscription of capabilities.
1.2.5. Need to make sure service is granted on the same basis it's being curtailed.	- Service will be curtailed under the same priority as was granted. Location of source and sink generators are estimated when service is granted. Process provides for mapping service back to zones where generation will be adjusted should service be curtailed.

ISSUE	DOCUMENTATION/COMMENTS
1.2.6. When the market expands, will the market gain firm rights outside the market that they do not own currently? Why should a Control Area gain firm rights that they did not have before – simply because the market expands?	- No, default will be level of firm that they would have had if the market did not expand. If additional firm room is available, Reciprocal Entities that agree to do so will allocate reaming room to prevent over subscription. Additionally, the calculation of NNL permits the RTOs to enhance granularity of determining all of the economic impacts on external Flowgates so that the RTOs can aggressively respond to a TLR.
1.2.7. Are you considering every generator a separate designated resource for all PJM load?	- No, Designated Resources are designated to their customer load. For example, Designated Resources within ComEd that are designated for customer load in ComEd will only count for that load and not entire PJM load.
1.2.8. Define "Historic NNL"	- Process to quantify the firm capabilities, for both network service and point-to-point inside the market, Control Area by Control Area that entities would have had if markets did not start or expand. "Historic" refers to historic or present process to quantify those values but does not refer to the level of firm for some past period.
1.2.9. How would you consider external transactions?	- They will be tagged and consider same as today. However, this proposal provides far more granularity to where actual generators will be moving to support schedule changes (this granularity will be in the form of the list of real-time marginal units).
1.2.10. Is there any coordination on non-firm?	See Sections 5 and 6
1.2.11. Loop flows are still not being accounted for. Therefore, if you calculate the ATC/AFC without accounting for loop flows, won't you oversell the Flowgate?	- Loop flows are estimated and accounted for in processed to help minimizing overselling of the Flowgates.
1.2.12. Need to work out a means for 6NN within PJM to be considered 6NN within MISO, and visa versa.	- Per suggestion of Stakeholders, process is provided to account for Priority 6-NN among all Reciprocal Entities.
1.2.13. In the day-ahead commitment, you (Tom Bowe) said that you will respect the NNL limits as related to the list of Flowgates that you agree on. Won't this falsely limit PJM?	The final draft of the Whitepaper, provides clarification to this question. The RTOs will not bind the Coordinated Flowgates to the NNL value unless the outage coordination and recent TLR activity show the need to limit the Flowgate in the day ahead commitment. The RTOs will further restrict their reciprocal Flowgates to respect one another's anticipated dispatches and schedules.

ISSUE	DOCUMENTATION/COMMENTS
1.2.14. Once an "Allocation of usage" of a Flowgate is determined by MISO and PJM, when additional parties come into the mix in the future (Duke), won't the Allocations have to be re-negotiated/re-calculated?	- Allocations may be recalculated if additional parties wish to join reciprocal process. Same process will be utilized to determine new parties' base usage and "Historic NNL".
1.2.15. If someone wants to purchase transmission for this summer, how will this be handled both before transition and after? How will existing purchased transmission be handled during the "transition"?	For this summer, same as today. Transmission service within a market will be converted and utilized according to that market's rules.
1.2.16. Complete and post the ATC/AFC Coordination agreement.	- ATC/AFC Coordination Agreement is an appendix of this paper.
1.2.17. Explain process of AFC Coordination with third/outside parties?	- Any party that wishes to participate can.
1.2.18. Explain ATC coordination across the EI.	- Only those that agree to will participate in the MISO/PJM ATC. AFC Coordination. Outside of that, different processes are used.
1.2.19. Explain conversion of grandfathered firm pt-pt	- grand father firm pt-to-pt will be converted per market rules where they apply or may remain same service and be tagged as today.
2. Contract Tie Capacity	
2.1. One Stop Shopping	- Out of scope of this process
3. Different Definitions/Procedures between RTOs	
3.1. Emergency & Restoration Procedures	Emergency & Restoration Drills held 11/02
3.2. Operating Procedures for Voltage Collapse & Stability	-Included in Attachment A of MISO & PJM Reliability Plans
4. NERC Regional Criteria and Reserve Sharing	
4.1. Define NERC Operating Policy changes, waivers, or certifications that are needed to permit security-constrained dispatch over multiple existing Control Areas and to allow flows to not be tagged between Control Zones. Potential Policy 1, Policy 3, and Policy 9 changes may be required.	Wavers are requested from NERC for Policy 3 and Policy 9. Policy 3 – Waiver request permission for PJM and MISO to provide market flow impacts to IDC instead of providing information by E-Tags. Policy 9 –Waiver requested to permit prioritization and reduction of market flow impacts on same basis as tagged interchange transactions. Waiver also requests that Market Flows be calculated actual flows rather than only using positive flows of 5% impact or greater. Security Coordination.
4.2. How does a market entity (PJM or MISO) respond to Reserve Sharing events?	Methods will be similar as today and will be defined within each market's rules. Reserve Sharing is beyond the scope of this proposal to manage congestion.
4.2.1. Events with ECAR, only (former) ECAR CA's respond?	- This proposal respects and does not change reserve sharing pools and arrangements.

ISSUE	DOCUMENTATION/COMMENTS
4.2.1.1. Studies and transmission margin already in place to handle the transfer of energy across network to needing party	- MISO and PJM have agreed to coordinate TRM/CBM to allow reserves to flow when called upon.
4.2.2. Events within ECAR, all of the market entity (PJM or MISO) generation resources respond?	- This proposal respects and does not change reserve sharing pools and arrangements.
4.2.2.1. This could impact transmission facilities where a transmission margin and associated studies are non-existent and cause overloads or other problems not previously anticipated	- Existing reserve sharing groups are not changed by this proposal.
5. Facilities in Close Electrical Proximity under Different RTOs	
5.1. Outage Maintenance Coordination	- Procedure included as appendix of this document.
5.2. Access & Expansion Planning	- MISO and PJM have agreed to coordinate Access & Expansion Planning. Procedure will be documented by separate agreement.
6. Market flow calculation, reflect ISN and SDX data	- Yes, State Estimator results that are used to calculate Market Flows utilize ISN and SDX data. State Estimators use of real time ICCP/ISN data for observable areas of market and SDX data for outlying areas.
7. Control Area/Control Zone responsibilities?	-Control Area responsibilities haven't changed. However, market operator may perform some of the responsibilities. - Control Zones recognize former Control Area boundaries where the market operator performs many of the traditional Control Area responsibilities. Control Zone boundaries are utilized when calculating historic NNL in PJM.
8. GLDF calculation. GLDFs depend on where the load is located. What is the % threshold?	- For Market flow calculation, the load is the entire market. For Historic NNL calculation, the load is the former Control Area. Percent threshold is 0% in order to calculate actual impacts and not only positive impacts of 5% or more.
9. Regarding wide area dispatch and network resources to network loads, Not all loads in PJM are firm network loads. Resource deliverability?	True. Designated resources are designated to their customer load. For example, Designated Resources within ComEd that are designated for customer load in ComEd will only count for that load and not entire PJM load.
10. Will you keep former CAs in the model?	Yes. Only for the purposes of calculating historic NNL, and calculating projected flows between what was once the CA's so that RC's do not lose the information they need to conduct their day-ahead studies.

ISSUE	DOCUMENTATION/COMMENTS
11. Define coordination that will take place between the market entity (PJM or MISO) and the IDC	- MISO and PJM will input market impacts to IDC and will follow curtailment orders received by IDC.
11.1. Define necessary IDC changes	- IDC will be changed to allow Market Flows to be prioritized and uploaded to IDC and curtailed/redispatch on same basis as interchange transactions R-tagged and entered into IDC. MISO and PJM will also provide more granular information to IDC regarding to sources and sinks of interchange transactions flowing in or out of the markets. IDC changes are documented in NERC Change Order 114.
11.2. Will coordination include updates of network model base cases and the Book of Flowgates?	Yes.
12. Industry oversight of PJM impact calculations.	- MISO and PJM will provide audit process to NERC. See Appendix K.
12.1. IDC cost issue	- MISO and PJM will pay for changes needed to implement this proposal in IDC.
12.2. Cost Allocation.	- MISO and PJM split 50/50 NERC costs for changes needed to implement this proposal in IDC.
13. Contingency plans? Critical path analysis.	RTOs committed to reliability. Implementation will be delayed until ready. Approval of plans, completion of IDC changes, testing/training or processes in IDC training server.
14. Selection process of market/TLR Coordinated Flowgates	-Process/Criteria to Determine Flowgates in this document
14.1. FTR and ARR auction in PJM April, are these shared Flowgates going to be included in the auction	-Yes, immediately prior to market implementation
14.2. How is it determined those Flowgates the market has an effective control of	- Criteria to determine Coordinated Flowgates is used to identify Flowgates ahead of time that market will have effective control of its flow over. See Section XX
14.3. What if there are Flowgates that see a significant flow from the market but the market doesn't have an effective control	- Criteria should screen those out. However, market can pay market/entities outside it market to provide redispatch. MISO will pursue agreements with neighboring entities
14.4. Need to ensure criteria for selecting Flowgates includes all Flowgates actually and significantly impacted by Market Flows.	Agreed, goal of criteria is to identify and include such Flowgates. PJM has sent the list of 240+ Coordinated Flowgates to all interested parties. In the two+ months parties have had to review the process only two entities has provided feedback (for a total of 4 additional Flowgates)
14.5. 5% threshold doesn't correct parallel flow problem. Need MW % usage.	- Criteria allows for inclusion of significantly utilized Flowgates with less that 5% impact on a case-by-case basis.
14.6. On the 5% limit, in the study you are referring to, because of the magnitude of the market flow, even 3% of a large amount of	Need to use a method to screen Flowgates so that Flowgates where market doesn't have effective control over are not included. For example, Market can't redispatch 1000 MW to remove 1 MW of flow.

ISSUE	DOCUMENTATION/COMMENTS
energy could easily overwhelm a Flowgate. Why use the 5% threshold – just when coming up with the list of market coordination Flowgates?	5% threshold is needed to develop list of Flowgates because market impacts will be calculated down to 0% on those Flowgates. If 5% screen is not used, Flowgates may be included where market have very ineffective control.
14.7. Develop process where significantly impacted (ex. 20% of Market Flow) Flowgates may be added to list.	- Criteria allows for inclusion of significantly utilized Flowgates with less that 5% impact on a case-by-case basis.
14.8. Need to address how we phase in list of Flowgates based on Market Growth Timeline	Studies will be performed based on areas included in the market for each time frame. The List of Flowgates Appendix shows how the initial studies have shown how this list will incrementally grow to support the Market Growth timeline.
14.9. If there is disagreement, who will make the final determination of whether a particular Flowgate is or is not included?	- NERC Operating Reliability Subcommittee or NERC Operating Committee.
14.10. Why not perform a study on all Flowgates in the BOF – but not add them unless they are needed. Then the calculation would already have been completed.	- All Flowgates in NERC Book of Flowgates will be included in initial screening. Criteria for determining Flowgates are exhaustive. Need to have process to add Flowgates on the fly if new Flowgate, not already in the IDC, is needed.
14.11. Why is it so important to come up with a relatively finite list of Flowgates right now. Then attempt to add Flowgates in the future "on the fly".	Threshold is applied when defining list of Flowgates since market flow is calculated down to 0%. - Always need to be able to add Flowgates on the fly if new constraint, not in the IDC, is identified.
14.12. Why not just have the market entity send information to the IDC and let it calculate the market impact?	- More accurate and efficient for market entity to calculate flows. Will enable market to market coordination outside of IDC and TLR.
14.13. "We (PJM) will allow MISO to audit us and determine if our redispatch and calculations are accurate and effective."	- MISO will also allow PJM to audit calculations.
14.14. Will all studies and their results be made posted or made public?	- As appropriate respecting confidentiality requirements.
14.15. Are MISO and PJM only considering Flowgates for the list that are within MISO or PJM?	- The RTOs have determined many 3rd party Flowgates per criteria.
15. What happens when MISO Firm and NNL + PJM Firm + NNL + 3rd parties firm and NNL + TRM and CBM > TTC?	

ISSUE	DOCUMENTATION/COMMENTS
15.1. How will day-ahead processes reduce planned flows when oversubscribed?	- No mechanism to ratchet down oversubscribed flows day ahead. Many Flowgate may already be over subscribed, by the current transmission providers. Will conduct Next –Day Reliability Analysis to ensure reliable system next day and identify required actions. Will use real time processes to reduce flows as needed. Additional MISO/PJM AFC coordination may avoid oversubscription of some Flowgates.
16. Sunset Provision	
16.1. Why not implement a sunset date for these procedures of December 1, 2003 – or such time as MISO implements its Day 2 market.	- MISO will utilize these procedures to enable its market to start. Will build upon, enhance, and adjust these procedures as needed with proper approvals.
17. Seams Agreement needs to be completed	- MISO and PJM plan to have a Coordination Agreement, which will include seams agreements.
18. Interaction with ATCo's Attachment K	
18.1. Possible joint redispatch agreement between ATC (and the generators on ATC's system) and PJM?	-May be handled in market-to-market environment. Should PJM's market expansion be delayed, MISO will pursue agreements with neighboring generators to achieve more economical redispatch results.
19. Define "RTO Area Wide Dispatch"	- Market area wide central, security constrained dispatch of generation in market.
20. Parallel Flows are not being paid for	-Clearly a compensation issue that needs to go to FERC.
21. Historic NNL values should not be reflected indefinitely in the future, and an appropriate mechanism to rationalize the historic flows to recognize eventual market conditions should be developed	- Absolutely. A new mechanism will need to be designed.
22. Which of these processes will change or go away once MISO and PJM are both operating their full markets? Which ones will remain in place?	- These procedures will remain in place, be built upon, and enhance for the Market-to-Market Coordination.

Appendix H- Training

The concepts in these proposals should not have a significant impact upon System Operators beyond the Operators of the RTOs. The reason that this impact rests upon the RTOs is that the RTO Operators will need to be trained to monitor and respond to the external Flowgates.

RTO Operator Training Impacts include

1. The ability to recognize and respond to Coordinated Flowgates.
   a. IDC outputs will show schedule curtailments and possible redispatch requirements.
   b. Must be able to enter constraint in systems to provide the redispatch relief within 15 minutes
   c. Must be able to confirm that the required redispatch relief has been provided and data provided to the IDC.
2. Capability to enter Flowgates on the fly.

Other Reliability Coordinator (RC) System Operators Training Impacts include:

1. The ability to take projected net system flows between an RTOs Control Zones versus only tag data to run day-ahead analysis (data to be provided by the IDC).
2. Need to develop a working knowledge of how relief on a TLR Flowgate can come from both schedule changes and redispatch on a select set of Coordinated Flowgates.
3. Can coordinate with an RTO Operator when the RC System Operator has a temporary Flowgate that they believe requires the implementation of the "Flowgate on the Fly" process.

Appendix I- PJM/MISO Generation and Transmission Outage Coordination

PJM and MISO will jointly develop protocols for sharing transmission and generation outage schedule data. PJM and MISO agree to the following with respect to transmission and generation outage coordination:

Exchange of Transmission and Generation Outage Schedule Data

The projected status of generation and transmission availability will be communicated between the RTOs while respecting data confidentiality agreements. All available information regardless of scheduled date will be shared. PJM and MISO shall exchange the most current information on proposed outage information and provide a timely response on potential impacts of proposed outages.

PJM and MISO both have their own different outage scheduling applications. Ideally these applications should both be supplemented with a common process to automate the exchange of this information between the systems to minimize manual duplication of information and to assure that both RTOs have access to the same outage information.

Until this is accomplished, the RTOs will use email as the primary method to communicate new outage requests, and changes to outage requests, to the potentially impacted RTO that has indicated an interest in receiving the facility outage information. The potentially impacted RTO shall respond via email (and voice communication) and identify any proposed outage that is expected to impact the reliable economic operation within their RTO.

The RTO's agree that this information will be shared as soon as the information is available but at least daily and more often as required by system conditions. The RTOs shall jointly develop a common format for the exchange of this information. The information shall include (but not be limited to) owning RTO's facility name; proposed outage start date & time; proposed facility return date & time; date and time when a response is needed from the impacted RTO to modify the proposed schedule; and any other information that may be relevant to the reliability assessment.

Each RTO will also independently provide information on approved and anticipated outages formatted as required for the NERC SDX System.

Evaluation and Coordination of Transmission and Generation Outages

As described above, the RTOs will exchange transmission and generation outage data. Initially each owning RTO shall provide the other RTO a listing of facility names that they will use to identify the facilities in their footprint and the other RTO shall respond by identifying which facilities they are interested in receiving outage information about. Updated facility lists should be exchanged at least twice a year. The RTOs will also exchange lists of operations personnel involved in outage coordination and outage coordination procedures.

The RTOs will utilize network applications to analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each RTO's outage analysis will consider the impact of its critical outages on the other RTO's system reliability, in addition to its own.

On a daily basis, the Operations Planning staff of each RTO shall jointly discuss outages for potential impacts. These discussions should include an indication of either concurrence with the outage or identify significant impact due to the outage as scheduled. Neither PJM nor MISO has the authority to cancel the other party's outage (except RTO to RTO tie lines). However, the RTOs will work together to resolve any identified outage conflicts. Consideration will be given to outage submittal times and outage criticality when addressing outage conflicts. If outage analysis indicates unacceptable system conditions, the RTOs will work with one another and the facility owner(s), as necessary, to provide remedial steps to be taken in advance of such proposed maintenance. If an operating procedure cannot be developed and a change to the proposed schedule is necessary based on significant impact, the RTO's shall discuss the facts involved and make every effort to act on behalf of the other RTO to effect the requested schedule change. If this change cannot be accommodated, the RTO with the outage shall notify the impacted RTO. A request to adjust a proposed outage date must include, identification of the facility(s) overloaded, and identify a similar time frame of more appropriate dates/times for the outage to be successful.

The RTOs will notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known. The RTO's will evaluate the impact of emergency and forced outages on the RTOs' systems and work with one another to develop remedial steps as necessary.

Outage schedule changes, both before or after the work has started, may require additional review. Each RTO will consider the impact of these changes on the other RTO's system reliability, in addition to its own. The RTOs will contact each other as soon as possible if these changes result in unacceptable system conditions and will work with one another to develop remedial steps as necessary.

Appendix J- PJM, MISO, and SPP ATC Coordination Document

Purpose and Background

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its ruling on the voluntary establishment of Regional Transmission Organizations (RTOs). This ruling, Order 2000, establishes a set of minimum characteristics and functions required of all RTOs. One of the functions required of RTOs by Order 2000 is Interregional Coordination. To fulfill this function, FERC requires that the RTO must ensure the integration of reliability practices within an Interconnection and market interface practices among regions. The integration of market interface practices among regions includes the coordination and sharing of data necessary for calculation of TTC and ATC, transmission reservation practices, scheduling practices, and congestion management procedures. The RTO is required to develop mechanisms to coordinate their activities with other regions. While it is not required to include the mechanisms at the time of RTO application, reporting requirements must be proposed by the RTO to provide follow-up details for how the RTO is meeting the coordination requirements.

Representatives from the former Alliance companies, Midwest Independent System Operator (MISO), and Southwest Power Pool (SPP) have been involved in a collaborative process to detail the data exchange requirements and mechanisms, data usage principles, and coordination of methodologies necessary to calculate TTC and ATC values for a seamless market interface.. This document describes the agreements reached to facilitate fulfillment of this specific coordination requirement imposed by Order 2000 on all RTOs. Subsequent to this process, a number of the former Alliance companies decided to join PJM. Therefore, PJM has become a party to this procedure.

I. Data Exchange

The vast Eastern Interconnection is highly integrated and capable of reliably transmitting energy over long distances. The operational control of this Interconnection is distributed among various transmission providers and Control Area operators. The localization of control is accomplished effectively on a regional basis by RTOs, which provide the direct supervision necessary to respond to transmission contingencies and operational emergencies in a swift and effective manner. Typically, these contingencies will impact the operation in the vicinity of the contingency. For example, the status of the transmission system in New England has very little impact on the operation of the transmission systems in the Mid-Continent and Southern regions. However, one should not conclude that each of these transmission systems can or should operate independently. Since the Eastern Interconnection connects all transmission systems within the Interconnection, the conditions within one region can impact the loadings, voltages and stability of others within the Interconnection. The magnitude of this impact is a function of generation status (including the generation serving specific loads), transmission configuration, and load level. Since the operation of one system will impact the operation of neighboring systems, data must be exchanged in order to maintain the reliability of the Interconnection.

The calculation of Total Transfer Capability and Available Transfer Capability is a forecast of transmission capacity that may be available for use by transmission customers. Such use also impacts the loadings, voltages and stability of neighboring systems. Because of this interrelationship, neighboring entities must exchange pertinent data in order for each entity to determine the TTC and ATC values for its own transmission system. This data is also necessary so that one RTO can refuse transmission service, if it is determined that the reservation request under consideration—if implemented—may overload facilities in the adjacent RTO.

The NERC SDX System currently is used to exchange statuses of generators rated greater than 150 MW, outages of all interconnections and other transmission facilities operated at greater than 230 kV, and peak load forecasts. This system has the capability to house daily data for the next seven days, weekly data for the next month and monthly data for the next year. Since this tool is currently being used and is maintained by NERC, the parties to this discussion believe that it would be prudent to use existing tools and methods as much as practical to accomplish the needed data tasks and avoid duplication of effort to the extent possible. Therefore the participating RTOs have agreed to fully populate the SDX System and update the data in the SDX System on a daily basis.

Therefore, the following data must be exchanged for each RTO to adequately determine its own TTC and ATC values and determine the impact of a proposed transmission service request on adjacent systems. Appendix A contains the procedural details of this data exchange.

Generation Outage Schedules from SDX

The projected status of generation availability over the next 13 months will be communicated between the RTOs using the existing NERC SDX System. The RTOs have agreed that this data will be updated at least daily for the full posting horizon and more often as required by system conditions. It is imperative that accurate and complete generation maintenance schedules are reflected in this data exchange. The RTOs have agreed that the 'return date' of a generator—either from a scheduled or forced outage—is necessary data for the determination of the TTC and ATC values. Therefore, each RTO has agreed that the generator availability data provided to the other RTOs will be the most current data available. If the status of a particular generator of less than 150 MW is used within an RTO's TTC/ATC calculation, the status of this unit shall also be supplied via the NERC SDX System.

Generation Dispatch Order

In addition to the availability status of each 'significant' generator in a neighboring RTO, the dispatch of the available generation is necessary to accurately model future transmission system conditions. Broad assumptions can be made concerning generation, such as scaling all available generation to meet the generation commitments within an area and then increasing all generation uniformly to model an export, or similarly uniformly decreasing all generation to model an energy import. Excluding nuclear generation or hydro units from this scaling would provide some level of refinement. It was agreed that this simplistic approach may not be adequate to identify transmission constraints and determine rational TTC/ATC values. On the other extreme, economic data could be shared to allow an economic dispatch to be determined for each level of generation commitment. It was recognized that this level of refinement was generally unnecessary, and the data will likely be considered confidential by the generation owners, and therefore unavailable. As a practical alternative, each RTO will provide each neighboring RTO a typical generation dispatch order or generation participation factors of all units on a Control Area basis. With this information, combined with the availability of the units as provided by the SDX System, a reasonably accurate dispatch can be developed as necessary for any modeled condition. The generation dispatch order would be updated as required by changes in unit statuses; however, it is envisioned that a new generation dispatch order would not be necessary more often than prior to each peak load season.

Transmission Outage Schedules from SDX

The projected status of transmission outage schedules over the next 13 months will be communicated between the RTOs using the existing NERC SDX System. The RTOs have agreed that these data will be updated at least daily for the full posting horizon and more often as required by system conditions. It is imperative that accurate and complete transmission facility maintenance schedules are reflected in this data exchange. The RTOs have agreed that the 'outage date' and 'return date' of a transmission facility (either from a scheduled or forced outage) are necessary data for the determination of the TTC and ATC values. Therefore, each RTO has agreed that the available data provided to the other RTOs will be the most current data available. If the status of a particular transmission facility operating at voltages less than 230 kV is critical to the determination of TTC and ATC of an RTO, the status of this facility would also be supplied via the NERC SDX System.

Transmission Interchange Schedules and Reservations

Schedules

The existing transmission reservations and interchange schedules of each neighboring RTO are also required to accurately determine the TTC and ATC values. Since interchange schedules impact the short-term use of the transmission system, the interchange schedules are necessary to determine the remaining capacity of the transmission system as well as determine the net impact of others' activities on the operation of each RTO. The resultant 'loop flow' has a direct impact on the amount of transmission service that can be accommodated by a transmission system. The parties have agreed that the interchange schedules will be made available to neighboring RTOs for their use. Because of the shear volume of this data, it may be more practical to post these data to a FTP site for downloading by neighboring RTOs as required by their own process and schedules. As an alternative, the parties have considered requesting NERC to modify the IDC to allow for selected interrogation by the RTOs. The actual method used to accomplish this data exchange will be determined in future discussions.

Reservations

Beyond the operating horizon, the impacts of existing transmission reservations are also necessary for the calculation of TTC and ATC for future time periods. The actual transmission reservation information will be exchanged among the RTOs for integration into their own TTC/ATC determination process. This information will also be made available via an FTP site. However, since a transmission reservation is a 'right to use' not an obligation to use the transmission system, the certainty of any particular reservation resulting in a corresponding interchange schedule is open to some level of speculation. This is especially true considering that the pro forma tariff allows firm service on a given path to be redirected as non-firm service on any other path. In addition, the ultimate transmission customer may not have, as yet, purchased all transmission reservations on a particular source-to-sink path. Further complicating this dilemma is that the duration or firmness of the 'second half' of the reservation may not be the same as the 'first half'. Therefore, since the portions of a source to sink reservation may not be able to be associated, prior to scheduling, double counting in the ATC determination process is a possibility. Therefore, information exchange regarding transmission reservations is necessary; however, the reservations themselves may not be incorporated into transmission models of the neighboring RTO. Each RTO will develop practices for modeling reservations, including external reservations, and netting practices for any allowance of counterflows created by reservations in electrically opposite directions. The procedures developed and implemented by each RTO to model intra-RTO reservations, reservations on external RTOs, and reservation netting practices will be shared with all adjoining RTOs.

Each RTO should also create and maintain a list of reservations from their OASIS that should not be considered in ATC calculations. Reasons for these exceptions may include grandfathered agreements that grant access to more transmission than is necessary for the related generation capacity and unmatched intra-RTO partial path reservations. If the RTO does not include it in its own evaluation, it should be excluded in other RTOs' analysis.

Load Data

Peak load data for the period (e.g. daily, weekly and monthly) will continue to be provided via the NERC SDX System. Since, by definition, peak load values may only apply to one hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. For the next 7-day horizon, it was agreed to either: supply hourly load forecasts OR daily peak load forecasts with a load profile. All load forecasts would be provided on a Control Area basis.

Calculated Firm and Non-firm Available Flowgate Capability (AFC)

The Available Flowgate Capability (AFC) is the applicable rating of the Flowgate less the projected loading across the particular Flowgate less Transmission Reliability Margin and Capacity Benefits Margin. The Firm AFC is calculated with only the appropriate firm transmission service reservations (or interchange schedules) in the model, while the non-firm AFC is determined with both firm and non-firm reservations (or interchange schedules) modeled. Each RTO will accept or reject transmission service requests based upon projected loadings on their own Flowgates as well as the loadings on 'foreign' Flowgates, this data is required to determine if a transmission service reservation (or interchange schedule) will impact Flowgates to an extent greater than the (firm or non-firm) AFC. Therefore, the Firm and Non-firm AFC for all relevant Flowgates will be exchanged among the RTOs. Each RTO will also limit approvals of Transmission Service Requests so as to not exceed the sum of the thermal capabilities of the tie lines that interconnect the RTOs.

Available Flowgate Rating

The Available Flowgate Rating is the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the Flowgate. The Flowgate rating is in units of megawatts. If the Flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions. The RTOs will provide the neighboring RTOs with (seasonal, normal and emergency) ratings as well as the limiting condition (thermal, voltage, or stability). This information will be updated as required by changes on the system, but these ratings are currently fairly static values and do not currently require frequent updating.

Identification of Flowgates

Flowgates that may initiate a TLR event must be considered in the RTO's TTC and ATC determination process. Foreign Flowgates that have a response factor equal to or greater than the distribution factor cut-off must be included in the evaluating RTO's model, as practical.

Configuration/facility changes (for EMS model updates)

Transmission configuration changes and generation additions (or retirements) are normally communicated via the NERC MMWG process. The short term TTC/ATC determination processes are (will be) based upon an EMS model of the transmission system. Since frequently comparing the MMWG cases with the RTO's EMS models would be a significant, if not impractical task, a mechanism must be instituted to ensure that all significant system changes of a neighbor are incorporated in each RTO EMS model. Although this information and a host of very detailed data are included in the MMWG cases, this data exchange mechanism will address the 'major' changes that should be included in the EMS based Models in a more timely manner. This type of data change would be similar to the 'New Facilities' Listings usually included in Interregional reports; however, explicit modeling information would need to be supplied along with the listing. It is envisioned that this data exchange should occur no less often than prior to each peak load season. In addition, the RTOs agree to exchange EMS models of their transmission systems as mechanisms can be established to facilitate this exchange.

II. Procedures

The three RTOs participating in this seams effort have agreed to ATC coordination procedures designed to minimize the likelihood of over-reserving or over-scheduling of the transmission system. The procedures call for exchanging information that enables each RTO to identify the effects of system conditions in adjoining RTOs on their own Flowgates. These procedures also call for exchanging Flowgate AFCs with adjoining RTOs to recognize limits on foreign Flowgates as well as their own Flowgates as each RTO accepts Transmission Service reservations and/or schedules that transmission service.

These procedures describe the process for exchanging near-term planning information and AFCs. Each RTO will have its own internal procedures for incorporating information provided by the adjoining RTOs in their power flow models and utilizing foreign Flowgate information when granting and scheduling transmission service. How these internal procedures work are not part of the coordination procedures. Each RTO can use different internal procedures and still accomplish acceptable coordination.

The following sections describe the ATC coordination procedures each RTO will follow. The ATC coordination procedure will be integrated by the RTOs into their own internal procedures for creating power flow models for determining AFCs. The ATC coordination procedures can be divided into two distinct activities: 1) calculation and posting of AFCs and 2) granting and scheduling transmission service. Individual descriptions of each activity are detailed below. However, these two activities are inter-dependent. (See figures 1 and 2 below)

Calculating and Posting ATCs

Coordination of ATCs requires that system conditions in neighboring RTOs will be recognized and included when calculating AFCs. Therefore, each RTO will use AFCs for foreign Flowgates when evaluating transmission service requests. A flow diagram of the process that the RTOs will follow for calculating and posting ATCs is included in Figure1. The flow diagram describes AFC determination. AFC values can be converted to Control Area (CA) to Control Area ATC values by dividing the most limiting Flowgate AFC by its response factor.
The process was developed based on the following assumptions:

- Each RTO will develop its own set of Flowgates and their applicable ratings and margins. Adjoining RTOs will acknowledge foreign Flowgate limitations to the extent the owning RTO operates to its own Flowgate limitations.
- Power flow models will be developed on a periodic basis to calculate AFC using information available via the data exchange from adjoining RTOs.
- AFCs are to be updated (i.e. decrement AFC using response factors and reservations) on a continuous basis but no less frequently than:
    - Once every two (2) hours for hourly and daily AFCs
    - Once a day for monthly AFC
- Each RTO will determine the response factors for local and foreign Flowgates for use by the individual RTO.
- Each RTO will post CA-to-CA ATC and/or Flowgate AFC for both their own Flowgates and adjoining RTO Flowgates. This allows transmission customers to view postings that may impact their ability to obtain transmission service
- Each RTO will compare adjoining RTO Flowgate AFCs they calculate with the AFC exchanged by the RTO responsible for the Flowgate for similar time periods and types of service. Where significant differences are caused by factors other than the recognition of different transmission services sold by each RTO, the RTOs will, either individually or on a joint basis, take steps to improve the AFC calculation process.
- Each RTO will update their own Flowgate AFCs on the data exchange. The data exchange update should be done at the same time the OASIS postings are updated to assure consistency in the data used by others. The participating RTOs will post these data no less often than once per hour or more often if necessary.
- An RTO will use the foreign Flowgate AFCs provided via the data exchange in their respective ATC determination processes. If valid (i.e. 'fresh') foreign AFC values are not available from an RTO, the calculating RTO will default to use the local RTO's current AFC value for the foreign Flowgates.

- The participating RTOs have agreed to monitor their processes and shorten the periodicity if they find overselling of transmission service or underutilization of the transmission system is occurring. (Note: The periodicity that is used to post AFC on the data exchange and the periodicity used by the participating RTOs accessing and utilizing foreign Flowgate information in the ATC determination process is an ATC coordination issue. This time lag represents the amount of time each RTO continues to do business without recognizing recent commitments of other RTOs). .
- All participating RTOs shall use the response factor cut-off that the owning/operating RTO uses for their Flowgate in their ATC determination efforts.

The sequence for calculating and posting AFCs is summarized below. Refer to Figures 1 and 2.

1. Each RTO will have its own periodicity for calculating (i.e. full network analysis) and updating AFCs. A RTO may have several periodicities depending on the service being offered (i.e., hourly AFC for the first 7 days may be updated once an hour, daily AFC for days 8 through 31 may be updated once a day and monthly AFC for months 2 through 13 may be updated once a week).
2. Each RTO will utilize data from the data exchange and the SDX as inputs to model development. These power flow models will also reflect system conditions in adjoining RTOs.
3. The power flow models will provide Flowgate base flows used to determine AFC and will be used to calculate response factors for CA-to-CA transactions.
4. Before utilizing calculated AFCs from the power flow models, a check will be made whether it is a foreign Flowgate. If it is a foreign Flowgate, the AFC value from the data exchange will be used unless the time stamp indicates the data exchange supplied data is 'aged'. If the foreign RTO data is aged then the AFC from the power flow model is used.
5. If it is a local RTO Flowgate, AFC from the power flow model is used for posting on OASIS and sent to the data exchange for use by other RTOs.
6. A continuous function is shown on Figure 1 that checks for changes in AFC on all posted Flowgates. If the Flowgate is a foreign Flowgate, no action is taken. If the Flowgate is a local Flowgate and has changed, the changed AFC is posted on the data exchange. This is intended to capture the effects of periodic calculations of AFC and the effects of changes to AFC when transmission service is granted.

Granting and Scheduling Transmission Service

Coordination of ATC values is involved in the granting of transmission service in that service should not be sold if it results in projected loading on a Flowgate that exceeds the Flowgate operating security limits. A general flow diagram of the process that the RTOs will follow when granting transmission service is in Figure 2. The process was developed based on the following assumptions:

- It is assumed a request for transmission service will be refused if AFC is not available. A request will not be refused if there are alternatives that can be used to create AFC (bumping lower priority service, offering higher price for same priority service, customer initiated redispatch, etc.).
- The RTOs are updating Flowgate AFCs as transmission service requests are accepted.
- A check will be made of all foreign Flowgates that are impacted by the pending transmission service request to ensure that they have been updated in the data exchange.
- Response factors for all Flowgates are calculated by each RTO.
- This process assumes that other mechanisms are in place to ensure that partial path issues that may result in inadvertent double counting the same transmission service is addressed. These are coordination details that need to be addressed.
- This process addresses only limitations that can be quantified or equated to thermal limits. Other reviews such as voltage, stability and network analysis may be required before granting the service.

The sequence for granting and scheduling transmission service is summarized below.

1. When a request is received, the set of response factors for the specific source and sink will be checked for impacts on foreign Flowgates. If there are no foreign Flowgates with impacts, the request will be processed without further consideration of foreign impacts.
2. If a transmission service request impacts a foreign Flowgate by equal to or greater than the response factor cut-off, the process is to check whether there has been a recent update of the foreign AFC via the data exchange. If the data exchange has been updated the foreign AFC will be decremented accordingly.
3. If the data exchange has not been updated, the process will decrement the RTOs own calculated AFC of the foreign Flowgate.
4. This process is repeated for all impacted Flowgates. If all Flowgate AFCs remain positive after decrementing, the request is approved and its impact will be included in the next OASIS update.

5. If the request results in a projected Flowgate loading exceeding its operating limits, then the request should be denied and the OASIS postings remain unchanged.
6. As described in Calculating and Posting ATCs section, once the evaluating RTO OASIS is updated with AFC changes, these changes will be posted on the data exchange for the RTO's own Flowgates. The newly approved reservation will be available to adjoining RTOs as they calculate their own Flowgate AFCs.

Use Schedules Not Reservations for Horizons where Schedules Exist

Schedules should replace reservations in the power flow model being used to determine AFCs. This may result in additional transmission capacity being available if the schedule is less than the reservation or if the schedule is creating a counter-flow to a constraint.

III. Other Issues

As part of the ATC coordination, there are certain rights and responsibilities that are agreed to be reserved for the owning RTO. These rights include the sole determination of the AFC value to be honored by participating RTO's. The TRM and CBM values for each Flowgate will be determined by the owning RTO.

The modeling of transmission reservations for determination of AFC within each participating RTO remains a concern. Problems with partial path reservations, inadequate tag information, and accuracy in predicting actual energy flow are issues that every RTO must address. The balance between over or under utilization of the transmission system resides with the decision on which transactions to model in determining remaining AFC. As described previously, each participating RTO will share data on transactions and Flowgate impacts of modeled transactions. It will be each RTOs responsibility to determine which reservations and schedules are to be incorporated in their model to determine AFC values for the period in question. Each RTO will commit to standardizing this process as much as practical within RTO operating guidelines.

The congestion management plan that each RTO implements may affect the coordination process for determining inter-regional transfer capability. A reexamination of the treatment of foreign Flowgates may be necessary depending on the congestion management plans.

PJM/MISO/SPP
Flowgate Information Exchange Process

The following types of data will be exchanged among the RTOs for the purpose of setting up more accurate network modeling cases, determining the impact of other's transmission service sales on internal Flowgates, and for the purpose of honoring external Flowgates when selling transmission service.

Reservation Information – Transmission Service sold will be used by each RTO in determining the impact on internal Flowgates of service sold by the other RTOs.

Scheduling Information – Used for the same purpose as reservation information, except in the scheduling time frame.

Flowgate Ratings and Available Capability – When determining whether to accept a new transmission reservation, each RTO will honor the AFC values calculated by the RTO that "owns" the Flowgate.

System Information such as loads, equipment outages, generator availability and generation dispatch order.

Transmission Reservations

1. Transmission reservations that are in confirmed, accepted, or study mode will be exchanged via a file that contains all Transmission Reservations made on the RTO system for a minimum of 13 months and beyond this as necessary.

2. Transmission reservation data will be exchanged via two types of files, a base file and an update file.

3. The base file will be updated once a day and will contain all reservations on the RTO system for a minimum of 13 months and beyond this as necessary. This file should be generated and sent by 2330 each day.

4. Within each day, a file will be generated every hour which contains the new reservations in either confirmed, accepted, or study status within the last hour. The time that this file will be sent will be determined at a later date.

5. All files generated will have as the first record, the date and time the data was last updated. All dates and times will be in GMT or as mutually agreed.

6. Each RTO will use the reservations contained in these files for calculating base flow information.

7. The data to be included in the reservation file is as follows: OASIS number, Transmission Provider, Start Time, Stop Time, MW sold (All segments), Priority, Source/Sink. All times shall be in GMT or as mutually agreed.

Scheduling Information

1. Schedules will be exchanged via a file that contains all schedules for the current and next day.

2. The data to be included in the schedule file is as follows: Tag #, OASIS number(s), Transmission Provider, Start Time, Stop Time, MW schedule, Source/Sink. All times shall be in GMT or as mutually agreed.

3. Schedule Files will be updated as new schedules come in.

Flowgate Ratings and Available Capability

1. Total Flowgate Capability (TFC) and Available Flowgate Capability (AFC) information will be exchanged via a file that contains this data for a RTOs Flowgates for a minimum of 13 months and beyond this as necessary.

2. TFC and AFC data will be exchanged via two types of files, a base file and an update file.

3. The base file will be updated once a day and will contain all TFCs and AFCs on the RTO system for a minimum of 13 months and beyond this as necessary. This file should be generated and sent by 2330 each day.

4. The update file will be continuously updated during the day as new transmission reservations are accepted, confirmed, or placed in study mode. This will be done at the same time as the OASIS posting is made.

5. Once Flowgate values are received, decisions to sell service will be made using internally calculated response factors on the external Flowgates.

6. This file will be considered old when it is not updated as follows: 2 hours for either hourly or daily AFCs, 1 day for monthly AFCs.

System Information

1. The NERC SDX System is the vehicle to exchange system information.

2. SDX data will be updated at least daily for all time horizons through month 13.

3. Load Data will supplied as follows: Daily peak forecasts (for 30 days) and monthly peak load forecasts for months 2 through 13. For the next 7 day horizon, hourly load forecasts OR daily peak load forecasts with a load profile will be provided. All of the above load forecasts would be on a Control Areas basis.

4. Transmission outages (including critical lower capability facilities), forced outages and return dates, and generation availability will be provided.

5. Generation dispatch order will be exchanged to determine appropriate generation dispatch for various scenarios.

PJM/MISO/SPP
AFC Rating and AFC File Format

Each Filename would have the name: RTONAME_Flowgateinfo

The format of the file is as follows:

1. The first record of the file should contain the date and time the data was calculated in the following format: mm/dd/yyyy xx:xx:xx

2. Each Record of the file following the first record should indicate Flowgate ratings and values as follows:

   - The first letter of each record indicate the time of the Flowgate record as follows:
   - Y = Year, M = Month, D = Day, and H = Hour

   - The second letter of each record indicates whether the record is a firm or a non-firm record type with F meaning Firm and N meaning Non-Firm

   - Following these two record type indications would be entries indicating the timeframe of the values given in the record, the Flowgate name, the Total Flowgate Capacity (TFC) for each period (with TRM and CBM already excluded), and Available Flowgate Capacity (AFC) for each period.

An example for each time frame is as follows:

YF, yyyy-yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,, AFCX
MF, mm/yyyy-mm/yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
MN, mm/yyyy-mm/yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
DF, mm/dd/yyyy-mm/dd/yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
DN, mm/dd/yyyy-mm/dd/yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
HN, mm/dd/yyyy/hh-mm/dd/yyyy/hh, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX

Where:

All Dates and Times are in CST
yyyy = year
mm = month (1=Jan, … 12=December)
dd = Day of the month
hh = Hour of the day (Hour Ending 1 through Hour Ending 24)

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Appendix K- Audit Procedures

MISO and PJM Market Flow, NNL, and Economic Dispatch Audit Procedure

MISO and PJM each under go rigorous internal and external audits of their processes (including SAS 70 Type II audits) to ensure they document processes, have proper control checks on their processes, and strictly follow the processes. Employees are required to follow the processes as a condition of employment at each organization. Further, MISO and PJM each are independent organizations and adhere to FERC's requirements for independence.

MISO and PJM will be calculating Market Flow, prioritizing those flows, and providing them to the IDC. The NERC IDC will calculate curtailment and redispatch requirements based, in part, on the MISO and PJM provided inputs. To provide even greater confidence that MISO and PJM are following the established processes for calculating these IDC inputs, MISO and PJM each volunteer to undergo this NERC administered audit process. The audit process will be pattern after the previous NERC Tag Audit. The audit process is as follows:

1. Once per month and after-the-fact, NERC will choose a time and Coordinated Flowgate to audit. The time chosen will typically be during an hour when TLR activity was occurring on one of the Coordinated Flowgates where MISO and/or PJM provide market flow values.

2. PJM and MISO will provide a record of loads, zonal generation, calculation, distribution factors, market flow calculations for the audit time, and resulting values provided to the IDC. Data confidentiality requirements of MISO, PJM, NERC, and FERC will be strictly followed.

3. NERC Staff will compare audit report results with values that were actually provided to the IDC for audited Flowgate and report any discrepancies to the NERC Operating Reliability Subcommittee (ORS).

4. The ORS will monitor this audit process and make recommendations for improvements as necessary.

5. Once three successful monthly audits are completed, the audits will be conducted quarterly.

Appendix L- Determination of Marginal Zone Participation Factors for PJM

In order for the IDC to properly account for tagged transactions, an RTO will need to send data describing the locations of the marginal generators that are either supplying generation to exports or are having energy replaced by imports.

In general, the RTO will be required to define a set of zones that can each be easily aggregated into a common distribution factor that is representative of the zone. This information must be shared and coordinated with the interchange distribution calculator. Following this step, the RTO must then send to the IDC participation factors for those zones (percentages that indicate on a real-time basis how those zones are providing or would provide marginal megawatts). Two sets of data are required:

- An IMPORT set, which indicates the next marginal units to supply replacement energy should the import transactions be curtailed, and
- An EXPORT set, which indicates the last marginal units used to supply the energy exported to other areas.

Marginal Zone Definition

Marginal Zones will be determined through collaboration of the RTO with the NERC Distribution Factor Working Group. As stated above, Marginal Zones should be comprised of generators that have electrically similar characteristics from a distribution factor point-of-view.

Participation Factor Calculation

Raw Marginal Zone Participation Factors are determined relatively simply. The RTO will examine the constraints and pricing information for the entire market footprint and determine the percentages of generation output in each zone that represents next marginal megawatts and last marginal megawatts. These will establish, for imports and exports, a set of participation factors that, when summed, will equal 100%.

If an RTO is comprised of multiple Control Areas, the RTO create a set of marginal zones for each Control Area and perform a Control Area Weighting. The marginal zones for a single Control Area will include all marginal zones for the entire market footprint. For very Control Area, the following weighting factors will be assigned:

- If the CA is Importing on an Inter-CA Schedule and Importing via Interchange:
  - Their factor for imports is equal to their Interchange value (assume all imports are to serve load), but no less than 1
  - Their factor for exports is 1 (they are not exporting)
- If the CA is Exporting on an Inter-CA Schedule and Exporting via Interchange:
  - Their factor for imports is 1 (they are not importing)
  - Their factor for exports is equal to their Interchange value (assume they are serving all exports), but no less than 1

If all Control Area factors are equal, then it is assumed that each zone is importing/exporting and equal share. Otherwise, all factors should be used to determine a Control Area participation factor that can be used to scale the Marginal Zone participation factors.

Next, the RTO should apply a Inter-CA Schedule Transfer Potential weighting. As an Inter-CA schedule approaches its limit (either contractual or reliability-imposed), its ability to move marginal generation across the transfer becomes reduced. Each CA to CA transfer within the market, therefore, must be appropriately reduced as well. The reduction function is as follows:

This provides a smoothed transition from unconstrained to constrained potential. For flows in the reverse direction, transfer potential is always assumed to be 100%.

These transfer potentials are applied to each set of marginal zone data as appropriate, resulting in a set of marginal zones that reflect the ability of the markets marginal zones to address Control Area balancing.

Appendix M- Flowgate Determination Process

This section is has been added to clarify:

- How initial Flowgates are identified (Figure M-1, Table M-1)
  - Process for Flowgates in the Coordinated Flowgate list
  - Process for Flowgates in the Reciprocal Coordinated Flowgate list
  - Process for Flowgates in the AFC List
- How Flowgates will be added (Figure M-2, Table M-2)
- How often Flowgates are changed (Figure M-2, Table M-2)

Table M-1

Step	Activity	Requirements	Detailed Description	Additional Documentation
1	Retrieve FG From List Of Known FG's	Retrieve FG from AFC list of FGs, NERC Book of FGs, and any other list of FGs.	• Retrieve the FG from the list of FGs. If a party wants us to consider a temporary FG it would go through the same process.	
2	Determine if FG passes >= 1 CMP Study	The decision determines if the FG passes at least one of the four CMP studies	• If the FG passes any of the studies, determine if there is mutually agreed upon reason why this should not be a coordinated FG. • If the FG does not pass any of the studies, it will be determined if there is a unilaterally decided reason for inclusion as a CF	CM Process -Section 3
3	Is There a Mutually Agreed Upon Reason This Should Not Be A Coordinated FG	Determine if there is a mutually agreed reason, despite passing one of the four tests, why this FG should not be considered Coordinated.	• If there is no mutually agreed reason why this FG should not be considered coordinated, set the FG equal to coordinated. • If there is a mutually agreed reason why this FG should not be considered coordinated, record the reason and set it equal to AFC FG.	
4	Set FG = Coordinated	The FG would be coordinated for the entity.	• The FG would be considered a Coordinated FG for the entity.	

5	Is FG Coordinated for >= 2 Reciprocal Entities	Determine whether the FG is coordinated for two or more reciprocal entities	• If the FG is coordinated for two or more reciprocal entities, it will be added to the CMP process as a reciprocal coordinated FG. • If it is not coordinated for two or more reciprocal entities, determine if it is a mutually agreed upon RCF.	CM Process -Section 6
6	Set FG = RCF	Set the flowgate equal to a reciprocal coordinated flowgate.	• Set the flowgate equal to a reciprocal coordinated flowgate.	
7	Is There a Unilateral Decision This Should Be A Coordinated FG	This decision determines if an entity wants to make this a Coordinated FG for a reason other than the four tests.	• If an entity decides to make this a coordinated FG, set FG = Coordinated. • Otherwise , set the FG = AFC.	
8	Set FG = AFC	The FG would remain an AFC FG.	• The FG would remain an AFC FG.	
9	Are there more FGs on the list?	Determine if there are any more FGs on the list that need to go through the CMP determination process.	• If there are no more FGs that need to go through the determination process, the process ends. • If there are more FGs that need to go through the determination process, retrieve the next one.	
10	Is This a Mutually Agreed Upon RCF	Determine if there is a mutually agreed reason this should be considered	• If there is no mutually agreed reason this should be considered a RCF, leave it as coordinated and check for more	

		a reciprocal coordinated flowgate.	FGs. • If there is a mutually agreed reason this should be considered a RCF, mark it as such.	

Table M-2				
Steps	**Activity**	**Requirements**	**Detailed Description**	**Additional Documentation**
1	Bi-Annual Review of the BOFs and AFC FGs	Retrieve the FG from the list of FGs for the entity running the process.	• Flowgate review should be done consistent with the IDC summer/winter base case changes, which would occur twice per year instead of Quarterly. Each base case update done at NERC for the IDC will need a certain amount of review just to make sure that current flowgates will continue to function with the new model. The FGs will be run through the process summarized in figure M-1.	
2	Monthly update of the Book of Flowgates and Data Exchange	Take monthly updates from book of flowgates, monthly full files and monthly incremental files and run them through the flowgate process and tests.	• Monthly the parties will perform full flowgate updates and synchronization. In addition the NERC Book of Flowgates is updated once a month. We will run these changes through the process summarized in figure M-1.	
3	Customer FG Requests	Any customer FG requests will also be subject to the tests and process above.	• Any customer FG requests will be run through the process summarized in figure M-1.	

4	Run Through FG Process and Tests	Run through FG Determination Process, Figure M-1	• Any FGs being reviewed or added will be run through the process summarized in figure M-1.	
5	AFC/CF/RCF List	Any FG additions or modifications would need to be committed to the repository of FGs and their qualifications	• Any FG additions or modifications would need to be committed to the repository of FGs, along with their qualifications	